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PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987 - December 1991

Primary Decision Documents

FEBRUARY 1986

READEX

PROPOSED PROGRAM

5-YEAR OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROGRAM FOR JANUARY 1987 - DECEMBER 1991

UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

PRIMARY DECISION DOCUMENTS
FEBRUARY 1986

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Decision Memorandum to the Secretary of the Interior: Adoption of a Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program for 1987-1991 (dated October 15, 1985), including:

Attachment 1--Proposed 5-Year Program Secretarial Issue Document Options Decision Sheet;

Attachment 2--Three Alternative Leasing Schedules for the Proposed Program;

Attachment 3--Maps of the Outer Continental Shelf Planning Areas; and

Attachment 4--Secretarial Issue Document

(Note: Appendices A through S of Attachment 4 and Subarea Deferrals Suggested by Commenters (Attachment 5) are not included in this document due to their bulk. Copies can be obtained by writing to the Branch of Program Development and Planning, Minerals Management Service, Mail Stop 645, U.S. Department of the Interior, Washington, D.C. 20240 or calling (202) 343-1072.)

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

OCT 15 1985

EMORANDUM

O: The Secretary

ROM: Assistant Secretary - Land and Minerals Management

UBJECT SUMMARY: Adoption of a Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for 1987-1991--Request for Secretarial Action

ISCUSSION

ection 18 of the OCS Lands Act, as amended, requires you to prepare and aintain an oil and gas leasing program for the United States OCS. It also equires that "The leasing program shall consist of a schedule of proposed ease sales indicating, as precisely as possible, the size, timing, and ocation of leasing activity which [the Secretary] determines will best meet ational energy needs for the five-year period following its approval . . . ."

he Minerals Management Service (MMS) has reviewed comments on the Draft roposed Program (DPP) which you issued in March 1985, revised the analysis, nd restructured the options for the Proposed 5-Year OCS Oil and Gas Leasing rogram for the period January 1987 to December 1991. Your selection of a roposed Program at this time is necessary to provide sufficient overlap with he current schedule and to allow advance planning for early sales in the new chedule to begin so that a hiatus in leasing can be avoided.

t is important to keep in mind the preliminary nature of this stage of the rogram development and approval process. The Proposed Program and the ecretarial Issue Document (SID) are scheduled to be forwarded in December 1985 o the Governor of each affected State, the Attorney General, and appropriate ederal Agencies for a 90-day review and comment period. Comments will be licited from potential oil and gas producers and the interested public by eans of a Federal Register Notice announcing the Proposed Program. Copies also ill be sent to the Congress. A draft environmental impact statement (EIS), rrently in preparation, will be issued shortly after the Proposed Program. he draft EIS will use as the proposed Federal action your decision on the roposed Program. The Proposed Program and draft EIS will be the focus of an rly 1986 meeting of the OCS Policy Committee. Following the 90-day comment riod for the Proposed Program, the SID will be revised once more to provide e basis for your decisions on the Proposed Final Program in late 1986 or rly 1987. Final approval of the 5-year leasing program can be made by you ter a 60-day waiting period before Congress and the President.

epared by: Paul R. Stang Ext.: 343-1072

Formulation of the Proposed Program requires your selection of the following:

- a configuration of planning areas (including possible deletion or other treatment of subareas);
- a leasing schedule;
- a presale process leading to decisions on the size of individual lease sales; and
- provisions to assure receipt of fair market value.

Attached for your use in making these selections are:

- a decision sheet (Attachment 1);
- three alternative leasing schedules (Attachment 2);
- maps of the proposed OCS planning areas (Attachment 3);
- the SID and Appendices on the Proposed Program (Attachment 4); and
- a description of subareas which commenters have suggested for deferral and potential Department of Defense (DOD) and National Aeronautics and Space Administration (NASA) exclusive use areas (Attachment 5).

The SID includes an analysis of specific factors which section 18 requires you to consider in formulating a 5-year leasing program. These factors, most of which are analyzed and arrayed by OCS planning area in the SID, include:

- geographical, geological, and ecological characteristics;
- equitable sharing of developmental benefits and environmental risks;
- relative needs of regional and national energy markets;
- other uses of the sea and seabed;
- interest of potential oil and gas producers;
- laws, goals, and policies of affected States;
- relative environmental sensitivity and marine productivity; and
- environmental and predictive information.

You are required to consider these factors in the selection of the timing and location of leasing "so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impacts on the coastal zone." Furthermore, the leasing program must be prepared and maintained in a manner consistent with the principle that leasing activities be conducted to assure receipt of fair market value for the lands leased and the rights conveyed.

THE MARCH 1985 DECISION ON THE DPP

As a point of reference, the DPP, which you issued in March 1985, slows the pace of leasing in comparison with the current program. It contains the following provisions:

- sales in 22 planning areas;
- 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales;
- no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin;
- a provision to accelerate sales in eight areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program);

- a presale process which results in focusing on promising acreage; and
- maintenance of current procedures for assuring the receipt of fair market value and a review of the question of whether the minimum bid level would be changed either in general or on a variable basis for different planning areas.

THE VALUE OF FLEXIBILITY

In 1981-82, when the analysis and decision process for the current program were underway, many analysts predicted that the price of oil and gas would continue to climb. Estimates of world oil prices reaching $60 (1982 dollars) per barrel or more by the end of the century were common. However, such price escalation has not yet occurred, and over the last 2 years, there has been a downward price trend. When the analysis was initiated, the actual price of oil was $29 per barrel (average free on board U.S. import price weighted by import volume), down from $34 in 1982. It has since dropped to about $26 as of August 1985. It is not clear whether this short-term downward trend will become a long-term trend. What is clear is that there is a far greater sense of uncertainty in perceptions and a far lower range of projections of future energy prices now than existed in 1981-82. The debate then was whether real long-term price increases would be 1, 2, 3, or more percent per year. The debate now ranges from projections of moderate near-term increases to forecasts of substantial near-term declines in oil prices if current trends in the world oil market continue. However, currently adequate oil supplies and low oil prices can obscure the need to take steps now to find adequate oil supplies through the rest of this century and the beginning of the next--for that is the period of production from areas leased in the new 5-year program.

Current prices and expectations about future oil and gas prices strongly affect the number of OCS tracts for which firms submit bids and the amount of their bids. Accordingly, the amount of acreage that will actually be leased by the program you choose will vary substantially depending upon events in the world oil market and companies' perception of how those events will influence future prices.

In formulating this leasing program, it is important to recognize that substantial economic and national security benefits may be realized from production of oil and gas found on OCS acreage that is leased during the 5-year term of the program. Such leases will come from acreage that is unleased as of 1987 or from leased acreage which is surrendered and leased again. These potential benefits make the OCS program one of the most beneficial of the Government's economic programs. In addition, the potential benefits would be realized largely in the form of Federal revenues which will help reduce future Government deficits.

The 5-year leasing program can influence the benefits realized because it controls the availability of investment opportunities in exploratory drilling on unleased OCS acreage, and thus in substantial measure, the ability of firms to adjust their OCS activities to emerging conditions in the world oil market. By determining the location and timing of OCS sales for the 1987-91 period, your final approval of a leasing program will set the bounds within which firms investing in exploration on the OCS will be able to make such adjustments during the 5-year period and up to a decade thereafter. If you choose a leasing program

with relatively small sales at less frequent intervals in fewer areas, the range of possible investments will be more limited. Such a choice may permit investors in OCS exploration to respond adequately to relatively low and stable world oil prices, but might not permit expanded leasing and exploration in response to higher price expectations. On the other hand, if you choose a leasing program with relatively large sales at more frequent intervals in more areas, the range of possible investments may be greater. Thus, while a more extensive leasing program could yield the same level of investment as a more restrictive program if lower prices are expected, a restrictive program would not allow substantial expansion in leasing and subsequent exploration if world oil price expectations were to rise more than anticipated.

Selecting a leasing program flexible enough to allow for necessary adjustments is also important given the structure of the OCS Lands Act. If a 5-year program is approved with relatively frequent sales in a relatively large number of planning areas in anticipation of the likelihood of high future energy prices, and if price expectations then wane, the program would be flexible enough to adjust without reinitiating the 2-year approval process required by section 18. On the other hand, if a scaled-down 5-year leasing program is approved and future energy prices appear to be rising faster than anticipated, the program cannot be scaled up without reinitiating the 2-year approval process. The cost to the Nation of such delay could be substantial. Flexibility in the program also needs to be balanced with stability in the program to allow affected parties and the oil and gas industry to plan efficiently and maintain public confidence in the program.

Public opinion on the Proposed Program may be strongly influenced by the scope you select. A more extensive program with opportunities for acceleration may be criticized by some States, environmental groups, and coastal residents, but would be well received by industry. These positions would likely be switched if a more limited program is selected. These opinions, already reflected to some degree in comments on the DPP and summarized later in this memorandum, also should be considered in deciding the appropriate level and frequency of leasing and the degree of flexibility built into the program.

SECTION 18 ANALYSIS

Both the June 1980 and the July 1982 5-year programs were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The court found that the section 18 analysis performed for the 1980 program did not fully comply with the statute, but that the 1982 program formulation fully complied with the statute and the guidance the court had set forth in its opinion on the 1980 program. The analysis undertaken for the DPP and refined for the Proposed Program is very similar to, but more extensive than, that conducted for the July 1982 program. For instance, estimates have been made of oil and gas resources, economic benefits to the Nation and environmental effects for the various planning areas to show more specifically how the potential benefits and costs can be affected by changes in the world oil market. Economic benefits were projected for a variation in oil prices from the actual 1984 price of $29 per barrel to an assumed low price of $19 per barrel, in conjunction with a real oil price increase of 1 percent and an 8 percent discount rate. These projections were supplemented with sensitivity analyses using real oil price increases of 0 and 2 percent per year, and a 6 percent discount rate.

As initially reflected in the DPP and confirmed in the attached refined analysis, both the per barrel and total estimated economic benefits for unleased and undiscovered resources are lower than those of the 1982 analysis. These reductions were caused in part by leasing since 1982 and projected leasing in the late 1985 to 1986 period, as well as the decline in oil price expectations. Declines in the resource estimates also contributed, especially in the Alaskan and Atlantic planning areas where disappointing exploration results were experienced. Most estimates of potential social costs (environmental and other costs not normally included in the cost of OCS operations) which might result from production are also lower than those of the 1982 analysis, but the drop for most planning areas is much more substantial than the drop in economic benefit. This is due not only to a reduction in projected leasable acreage and an improved safety record, but also to a revision in the assumptions used, which in retrospect greatly overstated potential social cost in the 1982 analysis.

Estimated net social value, the difference between estimated economic benefits and estimated social costs, is so large in every planning area that the social costs would have to be many times larger than estimated in order to reduce the expected net social value to zero. Table 12.1 in the SID shows that economic benefits are more than 17 times larger than the estimated social costs in one planning area and at least 85 times larger for all other planning areas for which there are estimated resources.

LOCATION, TIMING, AND SIZE

The following discussion of comments on and options for location, timing, and size of leasing incorporates the factors which you are required to consider under section 18 in formulation of the new 5-year program.

Nearly 350 comments were received in response to the release of the DPP in March 1985. A brief summary of comments appears in the Introduction of the SID, and a detailed summary appears in Appendix B.

Location Comments

Many Governors requested that specific areas be deleted from the leasing program. Alaska requested deletion of tracts near Unimak Pass, the Pribilof Islands, Yukon Delta, and Point Barrow and requested that no sales be held in the North Aleutian Basin until 1994. Delaware expressed concern about leasing in submarine canyonheads and within 12 miles of the State's territorial waters. Florida recommended permanent removal of the NASA/DOD Flight Clearance Zone from the South Atlantic Planning Area and requested deferral of a portion of the Eastern Gulf of Mexico Region.

Maine and Massachusetts requested exclusion of the Gulf of Maine. Massachusetts also requested the exclusion of Georges Bank, submarine canyons, and areas encompassed by the 400-meter isobath. Maryland recommended that areas off its coast be considered for tract selection. New Jersey and Virginia recommended deletion of areas within 50 miles of their coasts. New Jersey also expressed concern about leasing within biologically sensitive submarine canyon systems.

North Carolina requested deferral of areas shoreward of the 200-meter isobath off the State, a buffer zone around the Monitor Marine Sanctuary, the Ten Fathom Ledge, and Big Rock shelf areas. Oregon requested deletion of the outer portion (between 125° and 128° W. longitude) of the Washington-Oregon planning area, as well as Heceta, Stonewall, and Perpetua Banks.

Petroleum industry commenters generally opposed deletion of subareas from planning areas. One company did recommend that DOD activity areas receive special consideration. Two industry commenters recommended that certain leasing locations, such as frontier and deepwater areas, be given special treatment (such as longer lease terms, lower minimum bid, etc.) based on consideration of drilling results, economics, technology, and needs.

Several other commenters made deletion requests and additional comments pertaining to location of leasing.

Timing Comments

The Governors made several requests and recommendations concerning the timing of leasing. Alabama stated that more sales should be scheduled outside the Gulf of Mexico planning areas. Louisiana commented that leasing annually in the Gulf of Mexico and triennially in other planning areas does not provide for equitable sharing of leasing among various regions. Massachusetts requested that only one North Atlantic sale be scheduled in the next 5-year program. New Jersey recommended deceleration of the sale schedule for the Mid-Atlantic and North Atlantic planning areas. Oregon requested that enough time be provided for completing environmental studies prior to holding a sale in the Washington-Oregon planning area.

Several industry commenters stated a preference for biennial leasing in most planning areas outside the Gulf of Mexico.

Options for Location and Timing

Determining the location and timing of leasing requires decisions on the configuration of planning areas, the selection of planning areas to be included in the schedule, the order in which they will be offered for lease, and the frequency of sales within planning areas.

Since the March 1985 request for public comments (reproduced in Appendix M of the SID) a few minor modifications to planning area boundaries have been made as recommended by the Department of State. You are requested to: (1) confirm the configuration of planning areas on which the section 18 analysis has been performed; (2) select any or all additional planning area changes; (3) determine which subareas will be deferred from the 5-year program or flagged for special treatment during the presale process; and (4) decide whether the seaward boundary of the Northern California and Washington-Oregon planning areas should be revised to coincide with the limits of the Exclusive Economic Zone.

The quantitative analyses in the SID provide part of the basis you should use to determine in which planning areas sales should be scheduled. If the estimated benefits of oil and gas production in an area exceed the estimated costs, the area should be considered further for inclusion in the 5-year program. The net social value calculations show this to be the case for each of the planning areas for which there are estimated resources. Similarly, with respect to timing, the net social value calculations are divided into groups which can be used as a guide in deciding the frequency of sales in a particular planning area. In general, the higher the net social value group, the more frequently sales should be scheduled in that area, subject to the qualitative considerations discussed below.

It should be noted that deferral of one or more subareas within a planning area could move a planning area to a higher or lower net social value group and thus, could have an effect on decisions on the frequency of leasing. Any planning area affected by subarea deferrals will be reanalyzed for the Proposed Final Program so you can see what that effect would be. If subarea deletions are to be made, it would be preferable, given the analytical requirements of section 18, to select them now and/or early in the process of developing the Proposed Final Program. This will allow completion of the required analyses before the decision on the Proposed Final Program. The description of candidates for subarea deferral recommended by commenters is presented in Attachment 5.

In keeping with your statements this past summer, one of the specific options presented defers eight subareas off California: the area offshore the Pt. Reyes Wilderness; Pt. Reyes/Farallon Islands National Marine Sanctuary; the area in the immediate vicinity of Cordell Bank; the area offshore San Francisco Bay; the areas offshore Monterey Bay; the areas offshore Big Sur; Santa Barbara Federal Ecological Preserve and Buffer Zone; and Channel Islands National Marine Sanctuary.

By using the results of the section 18 quantitative analysis and industry interest rankings (see Table 13.2 of SID), a base schedule (Option 2-a) and five amendments (Option 2-b to 2-f) have been developed for your consideration. The combination of Options 2-a, 2-d, 2-e-i, and 2-f comprise a schedule nearly identical to that which you selected for the DPP. While many other combinations are possible, three schedules (see Attachment 2) showing all sales in Options 2-a, 2-d, and the combination of 2-a and 2-e have been developed. The other Options, 2-b, 2-c, 2-f, and combinations thereof, are relatively easy to envision and thus are not shown. The leasing activity which would result for each of these schedules is as follows:

Schedule	Maximum Number of Sales	Number of Planning Areas
Option 2-a	32	17**
Option 2-d	39	18**
Option 2-a & 2-e	37	21*

*Excludes St. Matthew-Hall, Aleutian Basin, Bowers Basin, and Aleutian Arc.
**Excludes those above, as well as Gulf of Alaska, Kodiak, Hope Basin, and Cook Inlet.

Option 2-a would schedule annual sales in the two areas in the "high" net social value group (Central and Western Gulf of Mexico) and triennial sales in 14 other areas in the "intermediate" group. Option 2-b would add a sale in the Straits of Florida based on the recently completed section 18 analysis for that planning area. Option 2-c would defer leasing in any or all of the following six planning areas: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin. Option 2-d would accelerate the schedule for Option 2-a by offering biennial sales in up to eight higher-value and/or higher-interest areas: Southern California; Central California; Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and St. George Basin.

Option 2-e would designate frontier exploration sales. Suboption 2-e-i would conform to your choice for the DPP, while suboption 2-e-ii would convert to frontier exploration sales, the sales in any or all of the following planning areas: North Atlantic; Mid-Atlantic; South Atlantic; and Washington-Oregon. A frontier exploration sale is the same as a standard sale except for an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations to help determine whether the presale process should begin. Thus, frontier exploration sales would be proposed for areas where there is greater uncertainty regarding industry interest. In either case, as part of the annual review of the 5-year program, an assessment would be made of the utility of continuing with these sales.

Option 2-f would add a single annual sale of selected blocks in areas other than the Central and Western Gulf of Mexico to include drainage and development blocks and blocks on which bids were rejected in the preceding calendar year. This would confirm a decision made for the DPP.

Option 2-g would provide for the possibility of acceleration of sales from a triennial basis in planning areas which have relatively high net social value and/or industry interest rankings. These are identical to the candidate areas specified in the DPP.

The schedules were derived on the basis of the ranking of planning areas by quantitative section 18 factors, as modified by the expression of industry interest when the two rankings differed significantly. For example, Beaufort Sea, Norton Basin, St. George Basin, Chukchi Sea, and North Aleutian Basin, which ha[illegible]ela-tively high industry interest rankings, were retained in Option 2-a even though the leasable resources and net social value for those areas are estimated to be negligible at $19 per barrel. On the other hand, Gulf of Alaska is ranked low by industry and thus was not included in Option 2-a. Washington-Oregon is part of the triennial option, but the first sale is scheduled for late in the 5-year program, 1991, to allow time to generate additional environmental information. Finally, South Atlantic, Mid-Atlantic, and Washington-Oregon which are estimated to have significant net social value at all oil price levels analyzed were not included in the acceleration option, Option 2-d, due to relatively low industry interest, while St. George Basin and Beaufort Sea were included due to relatively high industry interest.

Each of the three schedules, as well as the schedules which would result from selection of other combinations of options, reflect a balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone. This balance is based primarily upon the quantitative estimates of economic benefits and social costs as well as industry interest. However, to determine the timing and location of lease sales to provide a proper balance, as required by section 18(a)(3), you should consider, in addition, all the qualitative information on section 18(a)(2) factors. Further, your decision on the final 5-year program in late 1986 or early 1987 will need to be based upon any revision to the section 18 analyses, public comments, and the final EIS.

As indicated above, the attached analysis has been structured to be consistent with the court findings on the 1982 program. However, it should not be viewed as deterministic in any sense of the word. The framework for the analysis--planning for an uncertain future with limited information--sets the tone of the entire analysis. The estimates of economic benefits are based on the best data available, but are subject to considerable uncertainty as were the estimates in the 1982 analysis. To underline this uncertainty, a variation in starting oil prices ($19 to $29 per barrel) is used in this analysis rather than just point estimates as in the 1982 analysis. The social cost and marine productivity/environmental sensitivity analyses are even more uncertain than the economic benefits. The rankings of industry interest are simple averages and do not represent the relative strength of individual company preferences or the size of holdings of companies operating on the OCS. Furthermore, both the net social value and industry interest rankings are based on geologic data and economic/environmental assumptions which are highly subject to change as new information becomes available and analytical assumptions and techniques are refined. Such changes have the potential to alter the rankings, perhaps significantly. In light of these uncertainties and the requirement to consider all the qualitative as well as quantitative information required by section 18, your policy judgments are vital to meet the Act's balancing requirements for timing and location of lease sales.

Size Comments

In their comments on the DPP issued in March 1985, the Governors submitted several comments regarding the presale process. Alabama, California, Connecticut, Delaware, Georgia, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virginia stated general agreement with the concept of focusing on promising acreage. Some of these States also made suggestions to establish a presale process which defines even more precisely the acreage to be offered for lease. For example, Maine and Maryland proposed combining tract selection and areawide processes, and Maryland also suggested including a request for interest step for sales proposed in areas lacking commercial discoveries. Others requested better definition of the focusing on promising acreage process.

Alaska requested a return to the tract selection process. Florida, Massachusetts, and Washington recommended that smaller sale areas be defined to allow better impact analysis. Louisiana, Rhode Island, and Texas requested clarification of the presale process of focusing on promising acreage. These requests reflect a generally expressed need for better definition of this term. Oregon reiterated a request for abandoning the areawide leasing concept.

Most industry commenters recommended that the areawide presale process be retained in the next 5-year program. Several cited inequities in the procedures governing the submittal of positive and negative lease sale nominations, and they requested that the procedures be made similar for both. Two commenters expressed concern that a retreat from areawide leasing and an emphasis on consensus could cause unique exploration philosophies to be ignored or discounted.

Appendix P evaluates the effects of different sizes of lease sales that may result from the tract selection and areawide processes. The appendix was rewritten in July 1985 and is in the process of a further revision in light of comments received in response to the August 19, 1985, Federal Register Notice. New analyses will address the issues raised in the July 15, 1985, General Accounting Office report on areawide leasing. We will provide the information needed to meet the General Accounting Office recommendations "that the Secretary of the Interior consider the effects [of areawide leasing and other approaches] on competition and bid revenues in relation to anticipated benefits, and report his findings to the Congress." The revised Appendix P will be submitted for your review and possible action prior to distribution with the attached SID and other appendices when they are published later this year. This revision will enable the public to evaluate more fully your selection of a proposed program.

As of October 7, 1985, 17 comments have been received on Appendix P in response to the August 1985 Federal Register Notice. The responses from Maryland and Connecticut question the validity of using data from a mature producing area, the Gulf of Mexico, to draw conclusions about areawide or tract selection leasing for frontier areas. The respondents from three State agencies who responded expressed continued opposition to areawide leasing despite the statistics presented. New Jersey still supports focused leasing, and Louisiana favors a steadier paced leasing program as opposed to an accelerated program. The Maine State Planning Office believes that the appendix is more of a response to areawide leasing critics than a policy analysis. California finds that there is little data specific to the areawide leasing consequences for that State. The Natural Resource Defense Council disagrees with certain DOI assumptions, especially the 8 percent discount rate which they believe is inappropriately high. The Department of Energy concludes that areawide leasing has increased the present value contribution of total OCS payments to the Federal Treasury by about $3.5 billion and maintains that discount rates should be around 12 percent. Finally, the five respondents from industry all support the areawide leasing approach and basically concur with the analysis in Appendix P.

Options for Size

Under section 18, as validated by the court findings, the size of lease sales is determined by the presale process. Part III.B of the SID presents options for the presale process: focusing on promising acreage; tract selection; and areawide leasing. Tract selection was used until early 1983, areawide in mid- to late 1983, and a modified areawide approach roughly comparable to the "focusing on promising acreage" concept starting in 1984. For the DPP, you selected focusing on promising acreage for the presale process.

Tract selection as previously practiced differed from areawide leasing in two key ways: much less acreage was seriously considered for leasing; and more reliance was placed upon a consensus of Government and industry views in selecting the tracts to be offered for sale. Areawide leasing procedures allowed a far wider choice of tracts to be offered, providing opportunities for investment by firms with unique geological information and exploration strategies. Focusing on promising acreage identifies and offers acreage reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. Focusing on promising acreage also provides for far earlier resolution of conflicts than areawide leasing, especially for acreage with .ow resource estimates, low industry interest, and high use conflicts or concerns or high environmental value.

Regardless of which presale process is selected, it is important to note that size, in terms of acreage offered at a lease sale, is partially determined by the size of the planning area and its geology. In some planning areas, such as the Central and Western Gulf of Mexico, there are numerous interesting prospects scattered over large areas, while in others, such as the North Aleutian Basin, the most interesting prospects are concentrated in a relatively small area. Furthermore, even when the geology is similar in two planning areas, the acreage offered at a lease sale may be different if the planning areas are of different total acreage. The other key determinant of the size of a sale is the result of the presale resolution of conflicts involving other uses of the sea and seabed and environmental concerns.

Based on comments on the DPP and additional analysis, a number of alternative approaches for the presale process appear on the decision sheet. These are presented as candidates for the solicitation of comments in the Federal Register Notice announcing the Proposed Program.

MINIMUM BID AND BID ADEQUACY

The last two sets of options pertain to minimum bid and bid adequacy.

Minimum Bid and Bid Adequacy Review Comments and Discussions

Some Governors made recommendations with respect to raising the minimum bid level and enlarging the maximum tract size for lease sales. Alabama recommended raising the minimum bid in nonfrontier areas. Maryland and Rhode Island endorsed establishment of a minimum bid level set on a planning area basis rather than using a single figure nationwide. Rhode Island also recommended offering some tracts under a work commitment/fixed royalty bidding system.

The petroleum industry also addressed these topics. Most comments opposed raising the current minimum bid and recommended decreasing or eliminating it. The majority of comments concerning tract size did not support expanding the current maximum. Three companies did recommend enlarging certain tracts to tailor them to specific prospects.

A number of commenters contend that the current 5-year program lowers the average bid per acre and thus does not achieve fair market value. However, as noted by the U.S. Court of Appeals and the General Accounting Office, maximizing bonus bids per acre and assuring receipt of fair market value are different concepts. As described in Appendix P, the rates of leasing that result from different presale procedures may affect statistics such as the average bid per acre or the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. As is pointed out in Appendix K, the MMS bid adequacy procedures focus Government evaluations on tracts with fewer bids in order to provide added assurances for achieving fair market value.

Large sales tend to offer many low value tracts (e.g., those in deeper water or containing smaller prospects) along with the few potentially high value prospects that tend to be offered in smaller sales. Average bid statistics reflect these differences and show a decline as areawide and focused sales have proceeded, particularly in the Gulf of Mexico where a sizeable unleased inventory of good prospects (unleased acreage which is estimated to be profitable for lessees to acquire) had accumulated prior to the start of areawide sales. Declines in the average bid due to such effects should therefore not be viewed as an indication of failure to meet the fair market value requirement. Rather, they are the natural result of offering less prospective tracts and/or tracts which are more expensive to explore and develop, such as those in deeper water or where operating conditions are remote or hazardous. It also should be noted that the decline in average bids began in 1980.

Decreases in oil price expectations since 1982 contributed to the decline in average bids evident in the 1982-84 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to receive fair market value.

Minimum Bid Options

The current minimum bid policy, $150 per acre (subjected to reconsideration based on experience), was adopted through Secretarial decisions of March 11, 1982, and May 4, 1982. Although the increase to $150 per acre was largely regarded as a means of increasing bonus revenue and a means of helping to assure fair market value, the minimum bid can also be set to speed up or delay leasing in specific areas. In general, the higher the minimum bid, the later will be the leasing and exploration on higher cost, higher risk prospects. Thus, the minimum bid can be set to promote exploration or to prevent premature exploration. (See Appendix F, Part V and Appendix K.)

Option 4-a would maintain the minimum bid at $150/acre and allow you to determine on a sale-by-sale basis what changes, if any, are to be made.

Bid Adequacy Review Procedures Options

In the opinion on the 1982 program, California v. Watt (II), the court found that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the current tract evaluation and bid rejection procedures in order to satisfy the fair market value principle in section 18(a)(4) of the OCS Lands Act. These procedures are described in Appendix K.

Option 5-a maintains current bid adequacy review procedures and allows you to determine on a sale-by-sale basis what changes, if any, are to be made.

SUMMARY OF OPTIONS FOR DECISION

In summary, section 18 requires your formulation of a Proposed Program, including your selection of a configuration of planning areas, a leasing schedule, and a presale process. The options for your selection of a Proposed Program are listed on the attached decision sheet. Since this is a proposal and subject to subsequent decisionmaking based on suggestions received during the 90-day comment period, revisions of the section 18 analysis, and evaluation of the information which will be presented in draft and final EIS's, it is appropriate that you accompany your selection of the Proposed Program with any questions to which you desire responses from commenters.

Attachments

Proposed 5-Year Program SID Options
Decision Sheet

1. Planning Area Boundary Options:

   a. Use the configuration of planning areas and boundaries adopted for the Draft Proposed Program, with minor adjustments recommended by the Department of State. [This option is subject to modification by the selection of suboptions b, c, d, or e, below]. _____

   b. Revise the boundary between the North and Mid-Atlantic planning areas. _____

   c. Subarea deferrals from planning areas

      i. Make subarea deferrals at the 5-year program stage. Four different approaches to deferrals are outlined below.

         A. Defer subareas based on national security grounds--Department of Defense and National Aeronautics and Space Administration use areas--at the Proposed Program Stage. _____

         B. Defer the following subareas at the Proposed Program stage

            (I) Defer eight subareas offshore California as depicted in the SID: a) the area offshore Point Reyes Wilderness; b) Pt. Reyes-Farallon Islands National Marine Sanctuary; c) the area in the immediate vicinity of Cordell Bank; d) the area offshore San Francisco Bay; e) the areas offshore Monterey Bay; f) the areas offshore Big Sur; g) Santa Barbara Federal Ecological Preserve and Buffer Zone; and h) Channel Islands National Marine Sanctuary. _____

            (II) Other _____

         C. Select a set of subareas for further analysis with the decision on deferral postponed until the Proposed Final Program stage. In the interim, the set of subarea deferral candidates would be analyzed further by MMS and would be submitted to the public for comments. Those subareas would then be considered for deferral as part of the decision on the Proposed Final Program. _____

         D. Defer all decisions on subarea deferrals to the Proposed Final Program. _____

ii. Limit deferrals to the presale process, but "flag" subareas at the 5-year program stage for special attention during individual presale processes. _____

iii. Limit subarea deferrals to the presale process without "flagging" subareas but describe the process for making subarea deferrals in the presale process at the 5-year program stage. _____

d. Revise the seaward boundaries of the Northern California and Washington-Oregon planning areas to coincide with the limits of the Exclusive Economic Zone. _____

e. Other _____

2. Leasing Schedule Options:

a. Adopt the Draft Proposed Program base schedule of 32 standard sales, revised to begin in January 1987. [This option is subject to modification by the selection of suboptions b, c, d, e, f, g, or h, below]. _____

b. Add a single sale in the Straits of Florida in 1991. _____

c. Defer leasing in any or all of the following six planning areas:

i. North Atlantic _____
ii. Southern California _____
iii. Central California _____
iv. Northern California _____
v. Washington-Oregon _____
vi. North Aleutian Basin _____
vii. All six areas _____

d. Adopt biennial leasing in any or all of eight areas with higher value and/or higher interest:

i. Southern California _____
ii. Central California _____
iii. Northern California _____
iv. Eastern Gulf of Mexico _____
v. Beaufort Sea _____
vi. Navarin Basin _____
vii. North Aleutian Basin _____
viii. St. George Basin _____
ix. All eight areas _____

e. Designate Frontier Exploration Sales as follows:

i. Confirm any or all of the areas designated in the Draft Proposed Program for frontier exploration sales:

-Gulf of Alaska _____
-Kodiak _____
-Cook Inlet _____
-Hope Basin _____

ii. Add frontier exploration sale designation to all sales in any of or all of the following planning areas:

-North Atlantic ____
-Mid-Atlantic ____
-South Atlantic ____
-Washington-Oregon ____
-All four areas ____

f. Supplemental sales: Hold annual sales of rejected bid blocks offered in the preceding year and drainage and development blocks outside of the Central and Western Gulf of Mexico ____

g. Acceleration Provision: Provide for the possible acceleration of OCS sales in areas of higher value and/or higher interest from a triennial to a biennial basis (but not so as to increase the total number of sales in any planning area in the approved program).

i. Propose or request comments on any or all of the following triggers for the possible acceleration of OCS oil and gas leasing

	Propose	Request Comments
(A) Geologic Trigger: a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest	____	____
(B) Economic Triggers:		
(I) Activation of the International Energy Agency's oil sharing agreement	____	____
(II) Drawdown of the Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption	____	____
(III) Major disruption in Mideast oil shipments	____	____
(IV) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit over a specified period	____	____
(V) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of total domestic consumption of petroleum products over a specified period	____	____
(VI) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) rises by a specified amount or percent over a specified period	____	____
(VII) Net imports of petroleum (excluding those for the SPR) are projected by EIA to equal or exceed a specified percent of U.S. consumption of refined petroleum products	____	____
(VIII) Oil prices are projected by EIA to increase by a specified amount or percent or reach a specified level	____	____

ii. Select areas for the potential acceleration of OCS sales

(A) Any or all of the eight areas selected in the Draft Proposed Program decision:

-Southern California ____
-Central California ____
-Northern California ____
-Eastern Gulf of Mexico ____
-Beaufort Sea ____
-Navarin Basin ____
-North Aleutian Basin ____
-St. George Basin ____
-All eight areas ____

(B) All areas scheduled for triennial sales ____

h. Other ____

3. Size/Presale Process Options:

a. Focusing on Promising Acreage

i. Use the presale approach of focusing on promising acreage ____

ii. Solicit comments in the Federal Register Notice announcing the Proposed Program on possible techniques for implementing that approach ____

(A) - The recommendation of the Governor of Maryland that the presale process combine the tract selection approach for blocks within 50 miles of shore and areawide procedures for blocks beyond that limit. ____

(B) - Areawide sales in mature areas, tract selection sales in frontier areas. ____

(C) - The recommendation of the Governor of Maine that industry nominate in units of 100 blocks. ____

(D) - The recommendation of Massachusetts that nomination procedures be revised so as to request more detailed information from industry on areas of interest. ____

(E) - The recommendation of the API, NOIA, and a number of oil and gas producers that nomination procedures be revised so as to request more detailed information concerning "negative nominations." ____

(F) - Proposals to limit the amount of acreage leased by limiting the award of leases. For example, after deferring blocks, as appropriate, in order to avoid environmental and multiple-use conflicts, offer the remaining blocks, but place a cap on the number of leases to be awarded, such as a percentage of the total planning area or a fixed number determined on a planning area basis, with leases to be awarded in the order of the acceptable high bids. ____

(G) - Items A through F above ____

(H) - Other ____

b. Tract Selection Sales

i. Hold sales based on tract-specific nominations generally offering up to 2 million acres. ____

ii. Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations. ____

c. Hold Areawide Sales. For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described in the Secretarial Issue Document. ____

d. Other ____

4. Minimum Bid Options:

a. Maintain the $150/acre minimum bid and determine on a sale-by-sale basis what changes, if any, are to be made ____

b. Other ____

5. Bid Adequacy Review Options:

a. Maintain current bid adequacy review procedures and determine on a sale-by-sale basis what changes, if any, are to be made ____

b. Other ____

Current Leasing Schedule Overlap With Option 2-a for the Proposed Program
(Base Schedule of Standard Sales)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S	
ALASKA										10
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Herton										
Canyon Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
Aleutian Basin				92			S			
Kumagin						86				

Total 32

es to the left of the vertical line are in the current 5-year leasing schedule.
es to the right of the vertical line are a part of this option for the Proposed Program.

Sale not yet numbered. Sale numbers are those in the 1982 program.

is table has been prepared based on the latest available scheduling information.
inistrative considerations may delay the holding of a number of sales--Sales 111,
97, 107, 109, 86, 101, and possibly others. If such a change occurs, the leasing
edule would be implemented so as to factor in that change, consistent with the
eduling policy selected by the Secretary. This also applies to the following
schedule tables.

Current Leasing Schedule Overlap with Option 2-d for the Proposed Program
(Biennial Sales in up to 8 areas)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										13
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94		S		S		S	
PACIFIC										8
Southern CA		80			95		S		S	
Central CA	73					S		S		
Northern CA						91		S		
Washington-Oregon									S	
ALASKA										14
Beaufort Sea		87			97		S		S	
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107		S		S	
St. George Basin	70			89		101			S*	
N. Aleutian Basin				92		S		S		
Shumagin						86				
Gulf of Alaska			88							
									Total	39

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*The 26-month presale process for Alaska OCS sales results in the appearance that some of the areas proposed for biennial leasing have triennial leasing. A monthly schedule would show that the following 8 areas are proposed in this option for leasing as near to biennial as possible: Southern, Central, and Northen California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; St. George Basin; and North Aleutian Basin.

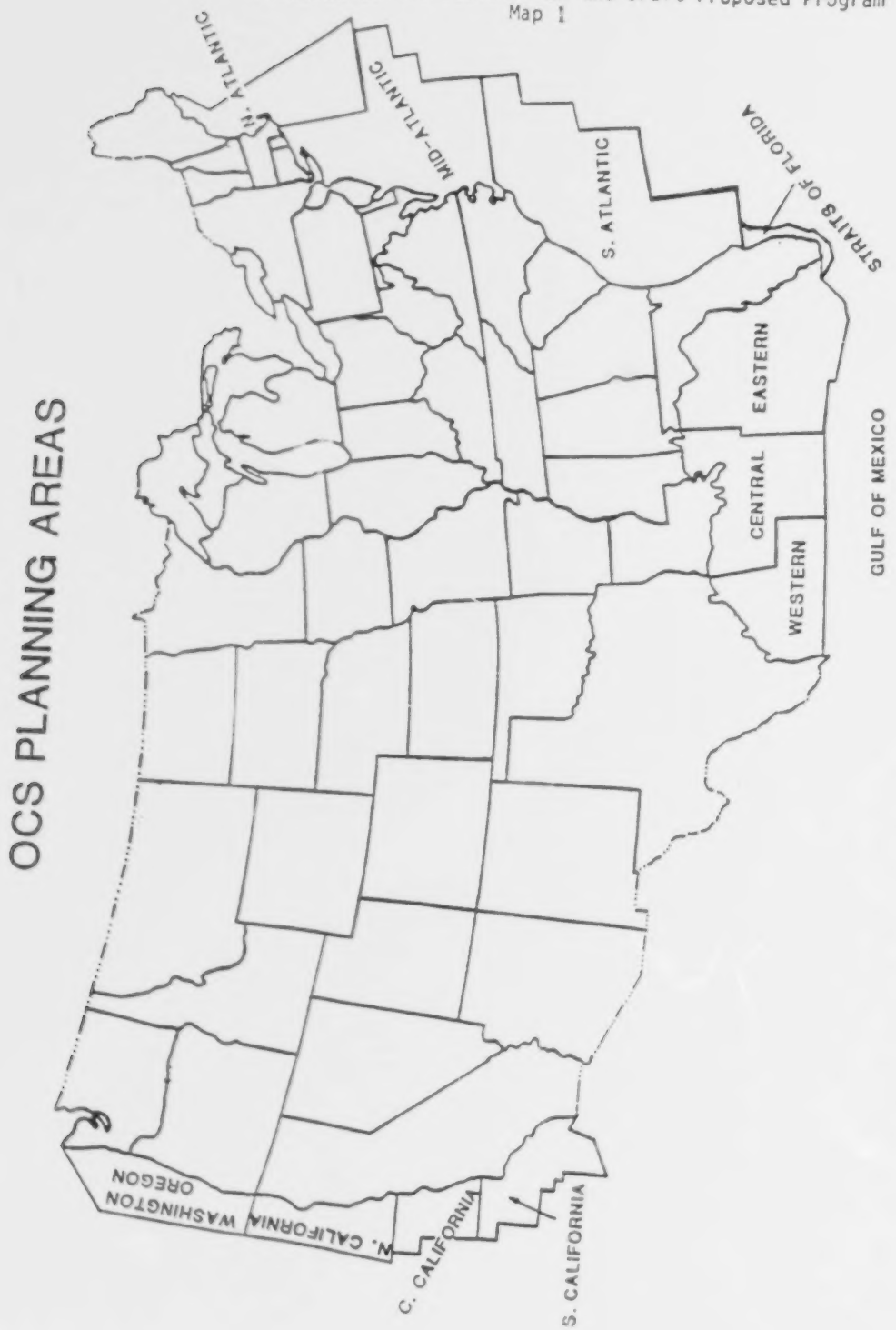
Current Leasing Schedule Overlap with Options 2-a and 2-e or the Proposed Program
(Base Schedule + up to 10 Frontier Exploration Sales)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96[S+]			S+	
Mid-	76			111			S+			
South	78			90			108[S+]			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S+	
ALASKA										15
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86			S+	
Kodiak									S+	
Cook Inlet									S+	
Gulf of Alaska						S+				
Hope Basin									S+	
									Total	37

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.
S+ = Frontier Exploration Sale.

Maps Depicting the 26 Planning Areas of the OCS
Pursuant to the Decision on the Draft Proposed Program
Map 1



OCS PLANNING AREAS

Map 2

Attachment 4

PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987 - December 1991

Secretarial Issue Document

OCTOBER 1985

PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for JANUARY 1987 - DECEMBER 1991

SECRETARIAL ISSUE DOCUMENT

OCTOBER 1985

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*In order to keep down printing costs, these lengthy pieces are not reproduced with this Secretarial Issue Document (SID) for the Proposed Program. They are, however, part of the decision materials considered by the Secretary for his decision on the Proposed Program. Copies of these pieces or other individual appendices can be obtained by special request to the Branch of Program Development and Planning, Minerals Management Service (645), 1800 C Street, N.W., Washington, D.C. 20240, (202) 343-1072.

Executive Summary

This revised Secretarial Issue Document (SID) provides the basis for the decisions by the Secretary of the Interior (Secretary) that will structure a Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for the period 1987 through 1991.

The program is being developed under section 18 of the OCS Lands Act, as amended. Under the requirements of section 18, as they have been interpreted by rulings of the U.S. Court of Appeals for the District of Columbia Circuit, the Secretary must consider a variety of factors bearing on the costs and benefits of leasing OCS oil and gas. The Secretary must then develop a schedule of lease sales which will "best meet national energy needs," balancing the potential benefits of the discovery of oil and gas against the potential costs.

The Proposed Program will be the second of three stages the Secretary is required to develop in the process of formulating the 5-Year OCS Leasing Program. Review copies of the Draft Proposed Program were issued to the Governors of coastal States, affected Federal agencies, and the public in March 1985. At the end of 1985 or the beginning of 1986, the second stage--the Proposed Program--is scheduled to be submitted for review to those same parties and to the Attorney General and Congress. The third stage--the Proposed Final Program--is scheduled for transmittal to the President and Congress in early 1987 with final approval by the Secretary slated for 60 days thereafter.

A draft environmental impact statement (EIS) will be issued with the second stage and the final EIS prior to the decision on the third stage. The Secretary's decision on the Proposed Program will serve as the proposal for the draft EIS.

This SID with its apperdices serves a number of functions.

1. It provides information on the various types of costs and benefits which the Secretary is required to consider, and it documents the sources and methods used in developing the new program.

2. It develops a framework and guidelines for balancing costs and benefits, recognizing the inherent limitations in the information about and forecasts of future conditions in the world oil market.

3. It sets forth options from which choices can be made concerning the size, timing, and location of lease sales in the Proposed Program and to assure the receipt of fair market value.

The SID for the Proposed Program has a number of new features which distinguish it from the SID for the Draft Proposed Program: it covers sales beginning in 1987 rather than mid-1986; it provides ranges and sensitivity tests rather than single-value estimates for a variety of quantitative measures; it contains refined analyses of benefits and costs; it summarizes and responds to comments on the Draft Proposed Program; it presents an estimate of the net social value of the base leasing schedule option; and it contains new decision options.

I. Introduction

A. Background

I.A.1. History

The 5-Year OCS Oil and Gas Leasing Program for 1987 through 1991 is the third program to be developed under section 18 of the OCS Lands Act, as amended (43 U.S.C. 1344). Prior to the OCS Lands Act Amendments of 1978, which added section 18 in its entirety, OCS leasing programs had been issued as a discretionary act of the Secretary of the Interior (hereafter, the Secretary). Regulations implementing section 18 appear at 30 CFR 256.14-20.

The first program prepared under section 18 received final approval in June 1980. That program scheduled 36 sales in 16 OCS planning areas for the period September 1980 through June 1985. Those sales were to be held using the "tract selection" approach which offered a limited amount of acreage, as described in Part III.B and Appendix P. Sales held under that leasing program resulted in the leasing of more than 2 million acres in 1981, the first year in which the 2 million acre level was surpassed since the announcement of the goal of leasing 10 million acres per year in 1974. Bonus bid levels of nearly $5,000 per acre on some tracts in 1981 provided strong signals that there were many good prospects for investment in exploration for oil and gas in the Government's inventory of unleased tracts.

The 1980 program was challenged in the U.S. Court of Appeals for the District of Columbia Circuit (hereafter, the court). /1 In its 1981 decision, the court found fault with the analysis performed for that program, but the court allowed leasing to continue and gave guidance for the formulation of the second program, then under development. The Secretary's compliance with the court's guidance was set forth in a SID and a set of appendices dated March 1982.

In July 1982, the second 5-year program developed under section 18 was given final approval by the Secretary. This program, currently in effect, scheduled 41 sales in 18 OCS planning areas between August 1982 and June 1987. Of those 41 sales, virtually all sales to be held after April 1983 were to use a new "areawide" approach to offer much more acreage, as described below in Part III. B and Appendix P.

The 1982 leasing program was also challenged in court. In a July 1983 opinion, the court upheld the 1982-1987 program formulation as having fully complied with the statute and the guidance it had set forth in its 1981 opinion. /2 Appendix A contains selected quotations from the OCS Lands Act, as amended, 30 CFR 256.14-20, and a discussion of the compliance of the development of this third 5-year program with section 18 as interpreted by the court.

/1 California v. Watt, 668 F.2d 1290 (hereafter, California v. Watt (I)), decided October 6, 1981.

/2 California v. Watt, 712 F.2d 584 (1983), (hereafter, California v. Watt (II)) decided July 5, 1983.

I.A.2. Development of the New Program

Under the procedural requirements of section 18, the development of a new program takes about two years. The initiation of development of the new program was announced in letters to the Governors of coastal States and to interested Federal Agencies, dated July 5, 1984, and in a Federal Register Notice published on July 11, 1984 (49 FR 28332). The Secretary's selection of a Draft Proposed Program was announced in letters to the Governors of coastal States and to interested Federal Agencies dated March 19, 1985, and in a Federal Register Notice published on March 22, 1985 (50 FR 11585).

The basic features of the Draft Proposed Program are as follows:

1. Planning Area Boundaries for the Draft Proposed Program

The Draft Proposed Program selection revised the July 1984 description by establishing outer boundaries for planning areas; reconfiguring the OCS from 24 to 26 planning areas by dividing the South Atlantic into two areas (South Atlantic and Straits of Florida) to allow a more concentrated review of those areas under the provisions of section 18; and reconfiguring the planning areas offshore California from two to three to allow a more concentrated section 18 review of those areas as well as to respond to public comments.

2. The Leasing Schedule for the Draft Proposed Program

Over the period mid-1986 through mid-1991, the Draft Proposed Program provided for 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales.

This contrasts with the current program (as approved in July 1982), which provided for 40 standard sales and 1 reoffering sale. The new draft schedule proposes the continuation of annual sales in the two highest-value, highest-interest areas: the Central and Western Gulf of Mexico. The Draft Proposed Program scheduled triennial sales in 15 other areas and thus slowed the pace of leasing in contrast with the biennial pace in the current 5-year program.

The first OCS sale for the area offshore Washington and Oregon since 1964 was proposed for 1991, given the value of that area's resources and industry interest. The schedule also proposed the first sale in Hope Basin, offshore Alaska, also in 1991 /1. The sales for these areas were proposed late in the 5-year period to allow time for the necessary environmental studies to be performed.

a. The Base Schedule

The base schedule proposed 33 standard sales in 17 planning areas. Eleven of those sales are sales carried over from the current to the new program.

b. Frontier Exploration Sales Offshore Alaska

Five frontier exploration sales were proposed offshore Alaska to increase the flexibility of the schedule to respond to possible future changes in prices and other economic conditions or improved geologic and geophysical data. These five sales were proposed for the Gulf of Alaska, Cook Inlet, Shumagin, Hope Basin, and Kodiak.

/1 The June 1980 program had proposed a sale in Hope Basin in May 1985.

These frontier exploration sales would include an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations. Responses to each Request will be used to help determine whether the approximately 2-year sale process should proceed in those areas. The scheduling of these sales provides flexibility to the program. Under current conditions, the Department would not necessarily see sales in these areas as viable. Yet conditions could change so that having the option to initiate and hold these sales could be in the Nation's interest. The annual review of the program under section 18(e) will also be used to determine whether to proceed with these sales.

c. Supplemental Sales

The schedule also included an annual sale for a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding calendar year. These sales would provide for: (1) The expeditious offering of blocks in which serious industry interest can reasonably be anticipated; (2) orderly development of OCS resources (increasing the potential for actual development and reducing the time necessary to bring new fields into production; and (3) minimization of costs of delay. These blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands Act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released at approximately the same time as the Proposed Notice of Sale. If it is determined that an EIS is required for one of these sales, revised presale milestones will be issued.

d. Areas in Which No Sales Are Proposed in the Draft Proposed Program

The schedule proposed no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin so as to concentrate management resources on other areas with higher resource potential and industry interest. No sale was scheduled for the Straits of Florida since this area was not yet analyzed as a separate planning area.

e. Acceleration (Flexibility) Provision

To comply fully with the statutory requirement to meet national energy needs over the 5 years of the program, the schedule should have the flexibility to respond to changing conditions. Thus, the Draft Proposed Program included a provision to accelerate sales in eight areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration would be considered include: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. Specific guidelines for the implementation of the acceleration provision were to be developed for the Proposed Program.

3. Size of Lease Sales in the Draft Proposed Program

It was proposed that the size of lease sales be determined by a presale process which results in focusing on promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a

consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis. Where strong environmental or other conflicts exist the focusing on promising acreage concept provides that these issues be addressed early so that, depending on the merits of each case, deferral of areas can be considered.

The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

4. Assurance of Receipt of Fair Market Value in the Draft Proposed Program

Section 18(a)(4) provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The policy option selected for the Draft Proposed Program maintains current procedures for assuring the receipt of fair market value. The option selected also provided for a review of the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas.

New Features of the SID for the Proposed Program

The new 5-year program is now planned to cover the period 1987 through 1991. The Draft Proposed Program focused on the period mid-1986 through mid-1991. The period covered by the new program has moved by 6 months because of various administrative considerations, including additional time allotted for the study of subareas which are potential candidates for deletion from the new program. The assumptions of the section 18 analyses have been made consistent with the new period to be covered by the program.

The SID for the Draft Proposed Program contained the preliminary analyses required by section 18. In response to the DOI's March 1985 request for comments, many commenters provided helpful comments and criticism of the analysis. This SID contains an updated and refined but still preliminary version of those analyses and decision options for the second stage of the development of the new program--the Proposed Program. The Proposed Program selected by the Secretary will serve as the proposed Federal action to be analyzed in the EIS. The final section 18 analyses and the final EIS will be a part of the decision materials for the Proposed Final Program scheduled for issuance in late 1986 or early 1987.

The Proposed Program will contain a schedule of proposed lease sales "indicating, as precisely as possible, the size, timing, and location of leasing activity" and program policies selected by the Secretary while at the same time reflecting the provisional nature of the "Proposed" stage.

The Proposed Program will indicate the proposed timing of presale steps for sales to be held beyond the current schedule. Sales will continue to be held in accordance with the current schedule until the new program receives final approval.

Under section 18(c)(2) of the OCS Lands Act and 30 CFR 256, the Proposed Program, the analyses on which it is based, and the draft EIS will be submitted for review to the Governors and local governments of coastal States and a Notice on the Proposed Program will be published in the Federal Register. Comments of the Governors and localities and of others on the Proposed Program and the draft EIS will be considered in the preparation of the Proposed Final Program and the final EIS.

Copies of the July 1984 and March 1985 Federal Register Notices appear in Appendix M. Development of the new program has also been the subject of consultation under the auspices of the OCS Advisory Board's Policy Committee, pursuant to regulations at 30 CFR 256.19.

Comments were received from Governors or their representatives, State and Federal Agencies, State legislators, local government entities, oil and gas industry members or associations, and from the general public. Most responses are briefly summarized below and all are detailed in Appendix B of this SID. Summaries of comments relevant to decision options also appear in Part III of this SID.

I.A.3 General Summary of Comments on the Draft Proposed Program

Approximately 337 comments were received on the Draft Proposed Program: 30 from the Governors of 23 coastal States; 4 from Members of Congess; 40 from companies or groups; 12 from Federal Agencies; 43 from State agencies and local governments; and 208 from individuals.

Section 18(a)(2) Factors Exclusive of Industry Rankings

Respondents frequently cited potential impacts that could result from OCS development, including potential effects on navigation and shipping, especially off California; effects on environmentally sensitive areas; potential conflicts with other uses of the sea and seabed including military uses; and potential fishing conflicts. Governors commented on onshore impacts on air quality, coastal infrastructure and the potential environmental and long-term economic impacts that could result from a disregard for equitable sharing. The States also expressed concern over potential conflicts with local coastal management plans. The biological significance and productivity of fisheries and their role in the Nation's food supply were identified as possible conflicts. Coastal tourism and recreation especially in New Jersey, New York, and California were cited as concerns. Among the many concerns expressed in comments from environmental and other interest groups, the following issues were most frequently cited: cumulative impacts, air quality, environmental sensitivity, deep water technology, public involvement, pace of leasing, fiscal impacts, other uses of the seabed and coasts, vessel traffic lanes, oil spill risks and response, ocean dumping of drilling by-products, infrastructure burdens, effects on coastal dependent economies, oil and gas transportation strategies, and whales and other marine migratory species.

Numerous comments focused on the need for equitable sharing of developmental benefits and environmental risks. Louisiana commented that the 5-year program would place an even greater burden on the Gulf Coast, citing scheduling concessions to all areas of the country except the Central and Western Gulf of Mexico. The high risks of exploration and low hydrocarbon potential were frequently cited as reasons for removing California's north coast from leasing consideration. Local governments, especially in California, frequently commented that developmental benefits and environmental risks were inadequately considered in the Draft Proposed Program.

With respect to relative marine productivity and environmental sensitivity, the U.S. Environmental Protection Agency (EPA) and North Carolina believe that a broader view and use of more meaningful indicators of relative marine productivity should be adopted. New York commented that environmental sensitivity figures are misleading as to the environmental importance of a region. South Carolina, numerous local governments in California, and several environmental groups believe that the Draft Proposed Program does not adequately consider the relative marine productivity and environmental sensitivity of planning areas.

With regard to oil and gas transportation networks and strategies, several commenters cited navigation concerns and shipping safety. The Coast Guard expressed concern that conflicts, which may arise when leases are granted in and near existing and potential shipping lanes, have not been given adequate treatment in the Draft Proposed Program. The Coast Guard called for coordinating lease sale areas with a scheduled system-wide adjustment of sealanes. Areas off California were singled out as needing such consideration. The California Coastal Commission recommended that oil transportation by pipeline be required for all areas of the Pacific coast. Numerous local governments in California called for adequate consideration for navigation and sealanes; Ventura County recommended resolving transportation issues prior to leasing. Santa Barbara County recommended deleting tracts from leasing located in the Santa Barbara Channel Vessel Traffic Separation Scheme. Where mentioned in comments, pipeline transportation is generally favored over tankers.

Most comments on the topic of relevant environmental and predictive information recommended continuation of the environmental studies program, and in some cases a call was made for supplemental efforts to the existing program. The National Oceanic and Atmospheric Administration stated that certain sales in Alaska are scheduled too early to allow environmental studies to be completed before the exploration stage. Florida recommended no leasing in portions of the Eastern Gulf of Mexico, citing a lack of environmental studies data. Oregon called for formation of a Pacific Northwest working group to determine whether OCS areas off Washington and Oregon should be placed on the 5-year program schedule and to design an environmental studies program. Oregon expressed concern that 3 years is inadequate time to complete studies necessary to support a lease sale in the area and suggested establishing an environmental studies field office in Newport, OR, at the Mark O. Hatfield Marine Science Center; Washington made a similar request for a field office to be located in Washington. Florida Public Interest Research Group recommended sufficient funding and coordination to complete environmental studies.

Comments on Possible Changes to the Leasing Process

Many commenters expressed strong support for the Secretary's emphasis on consultation and consensus, the focusing on promising acreage concept, and the triennial pace of leasing in most areas outside the Central and Western Gulf of Mexico. Commenters asked for clarification of the focusing on promising acreage concept, particularly how it differs from both areawide leasing and the tract selection process. Similarly, the acceleration provision in the leasing process elicited many comments calling for clarification of how it would be implemented.

The presale process was the focus of numerous comments. There were frequent criticisms of areawide leasing and calls for a return to a tract selection process. Louisiana called for a description of specific prelease mechanisms and procedures. Maine proposed combining the best features of both the areawide and tract selection leasing process, specifically recommending a "middle ground" option. Maryland proposed a split presale process employing areawide leasing in deepwater areas and tract selection for nearshore areas. Rhode Island called for a Request for Interest step to be used in unproven areas such as the North Atlantic.

Ten States (Alabama, Connecticut, Delaware, Maryland, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virgina) expressed general agreement with the proposed prelease process. Industry continued to favor the areawide approach. Several companies including Chevron, Marathon, and Exxon as well as the American Petroleum Institute (API) expressed some reservations about adding unnecessary steps to the presale process.

With regard to the proposed means for pursuing flexibility in the leasing process, reactions were mixed. The U.S. Department of Energy endorsed the proposed acceleration provision. The EPA suggested altering diligence requirements as an alternative. Alaska, Massachusetts, and South Carolina stated a need for more information. Florida has concerns that accelerated leasing will conflict with the goals of the environmental studies program. Oregon requested deletion of the acceleration provision. Rhode Island called the accelaration provision a "good idea," but desires more information. A few commenters said that the acceleration provision may be inconsistent with the OCS Lands Act. Numerous local government and environmental groups' responses opposed the acceleration provision, but industry generally endorsed the proposal. Several industry responses, including BP Alaska, NOIA, Tenneco, Sohio, Union Texas Petroleum, Exxon, WOGA, and the U.S. Chamber of Commerce emphasized the need for overall reliability in the program.

Commenters' Size, Location, and Timing Recommendations

Opinions on the size of sales as determined by the prelease process were divided. Areawide leasing was generally advocated by industry and opposed by others. Those opposed frequently called for a return to tract selection procedures. The concept of "focusing on promising acreage," while generally well received, caused commenters to reserve judgment pending a fuller explanation of its meaning. Some States, Massachusetts for example, recommended focusing on potential oil- and-gas-bearing structures or physiographic regions rather than on geographic boundaries of planning areas. Texas, on the other hand, expressed difficulty in discerning the practical difference between areawide leasing and focusing on promising acreage.

On the topic of location, Gulf Coast States generally indicated that more sales should be held outside the Central and Western Gulf of Mexico. Alaska agreed with the decision to drop St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin planning areas from the leasing schedule. Oregon gave qualified approval to including the Washington-Oregon planning area on the leasing schedule, but requested a seaward boundary of 125° instead of 128° W. longitude. State agencies and local governments generally opposed leasing off Central and Northern California. The City of Eureka, however, endorsed leasing in the Northern California planning area. Industry stated general agreement with the location of proposed sales. At least one industry response called for renewed emphasis on leasing in Alaska and California OCS regions, citing the potential for new resources that exists there. Citizen comments generally opposed leasing off California.

The triennial pace of leasing was generally viewed favorably. Louisiana and Texas expressed concern over annual sales in the Gulf of Mexico, but Alabama supported the pace and called for accelerating sales in the Eastern Gulf of Mexico if major discoveries are found in that area. Maine, Massachusetts, and New Jersey expressed reservations over the timing of sales in the North Atlantic planning area. Massachusetts stated that only one sale there during the 5-year period is warranted. Several California respondents alleged there was no slowing of the sale pace, since the number of planning areas was increased from 2 to 3. More than one California legislator commented that the reconfiguration, coupled with the introduction of supplemental sales, accelerated, rather than slowed, the pace in some areas. Numerous industry respondents preferred a biennial pace of leasing for most areas outside the Central and Western Gulf of Mexico.

General Accounting Office Report

On July 15, 1985, the General Accounting Office (GAO) published a report entitled "Early Assessment of Interior's Area-Wide Program for Leasing Offshore Lands." This report found that "more offshore lands have been leased and that exploration is progressing at a faster rate under the area-wide program." It also reported that it could not yet " assess effects on production, imports, prices, employment or total government revenues." The GAO concluded that competition had declined and that the "shift to area-wide leasing was responsible for an average reduction in bids of $541 per acre leased" out of the decline from $2,624 per acre under the tract selection program to $686 per acre.

The GAO recommended "that the Secretary of the Interior, in developing the next 5-year leasing schedule, consider the effects identified on competition and bid revenues in relation to anticipated benefits, and report his findings to Congress." Appendix P reviews the GAO analysis of competition and bonuses and analyzes the investment and revenue effects of the pace of leasing under different approaches. The results are summarized in Part III.B.

Appendix P

A revised Appendix P (Analysis of Tract Selection and Areawide Leasing Approaches) was issued several months after release of the Draft Proposed Program. It was sent to the Governors of coastal States for comment on July 16, 1985, and a notice announcing its availability for public comments was publisned in the Federal Register on August 19, 1985 (50 FR 33418). Seventeen comments were received on the analysis from 5 companies; 10 States; and 2 others.

General and Miscellaneous Comments

Topics most commonly addressed apart from section 18 considerations and those requested in the March 1985 Federal Register Notice included the following: expressions of support for OCS revenue sharing, calls for speedy resolution of the 8(g) issue, continuing support for the Congressional moratorium/1 and negotiation of a long-term agreement to protect environmentally sensitive areas off California, the need for alternative energy strategies based on renewable energy sources and conservation, and concern for the onshore impacts on coastal dependent economies. The States, as expected, continued the call for OCS revenue sharing. California and Texas want negotiations to resolve 8(g) concerns. Citizen response calling for continuation of the moratorium off California was heavy. Local governments in California frequently called for continuing the moratorium unless a long-term agreement on the status of sensitive areas can be achieved.

In view of these concerns, Secretary of the Interior Donald Hodel and members of the California Congressional Delegation announced on July 16, 1985, a preliminary agreement which would have allowed the leasing of 150 tracts out of 6,460 that had been under moratorium off California. The preliminary agreement was subject to receiving additional advice and comments. Secretary Hodel held a series of town hall meetings in 11 California cities in August to receive comments. Based on that information, over 2,000 pieces of correspondence, and additional analysis, he found that the preliminary agreement was not in the national interest and wrote to the Senate and House indicating so on September 5, 1985. On September 11, 1985, he testified before the House and on September 17, 1985, before the Senate, reporting his thoughts on the preliminary agreement.

A more detailed summary of comments may be found in Appendix B.

The following pages contain a copy of section 18 and a copy of maps depicting the 26 planning areas of the OCS pursuant to the decision on the Draft Proposed Program.

1/ The FY 1985 DOI Appropriation Act contained a restriction prohibiting the leasing of 44.8 million areas off California and in the North Atlantic.

I.A.4

Section 18 of the OCS Lands Act

"SEC. 18. OUTER CONTINENTAL SHELF LEASING PROGRAM.—(a) The Secretary, pursuant to procedures set forth in subsections (c) and (d) of this section, shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of this Act. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval. Such leasing program shall be prepared and maintained in a manner consistent with the following principles: 43 USC 1344.

"(1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments.

"(2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of—

"(A) existing information concerning the geographical, geological, and ecological characteristics of such regions;

"(B) an equitable sharing of developmental benefits and environmental risks among the various regions;

"(C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;

"(D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;

"(E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;

"(F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;

"(G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and

"(H) relevant environmental and predictive information for different areas of the outer Continental Shelf.

"(3) The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.

Fair market value.

"(4) Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

(continued)

Appropriations and staff, estimates.

"(b) The leasing program shall include estimates of the appropriations and staff required to—

"(1) obtain resource information and any other information needed to prepare the leasing program required by this section;

"(2) analyze and interpret the exploratory data and any other information which may be compiled under the authority of this Act;

Environmental studies and impact statement.

"(3) conduct environmental studies and prepare any environmental impact statement required in accordance with this Act and with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)); and

"(4) supervise operations conducted pursuant to each lease in the manner necessary to assure due diligence in the exploration and development of the lease area and compliance with the requirements of applicable law and regulations, and with the terms of the lease.

"(c)(1) During the preparation of any proposed leasing program under this section, the Secretary shall invite and consider suggestions for such program from any interested Federal agency, including the Attorney General, in consultation with the Federal Trade Commission, and from the Governor of any State which may become an affected State under such proposed program. The Secretary may also invite or consider any suggestions from the executive of any affected local government in such an affected State, which have been previously submitted to the Governor of such State, and from any other person.

Publication in Federal Register.

"(2) After such preparation and at least sixty days prior to publication of a proposed leasing program in the Federal Register pursuant to paragraph (3) of this subsection, the Secretary shall submit a copy of such proposed program to the Governor of each affected State for review and comment. The Governor may solicit comments from those executives of local governments in his State which he, in his discretion, determines will be affected by the proposed program. If any comment by such Governor is received by the Secretary at least fifteen days prior to submission to the Congress pursuant to such paragraph (3) and includes a request for any modification of such proposed program, the Secretary shall reply in writing, granting or denying such request in whole or in part, or granting such request in such modified form as the Secretary considers appropriate, and stating his reasons therefor. All such correspondence between the Secretary and the Governor of any affected State, together with any additional information and data relating thereto, shall accompany such proposed program when it is submitted to the Congress.

Leasing program, submittal to Congress.

Publication in Federal Register.

"(3) Within nine months after the date of enactment of this section, the Secretary shall submit a proposed leasing program to the Congress, the Attorney General, and the Governors of affected States, and shall publish such proposed program in the Federal Register. Each Governor shall, upon request, submit a copy of the proposed leasing program to the executive of any local government affected by the proposed program.

"(d)(1) Within ninety days after the date of publication of a proposed leasing program, the Attorney General may, after consultation with the Federal Trade Commission, submit comments on the anticipated effects of such proposed program upon competition. Any State, local government, or other person may submit comments and recommendations as to any aspect of such proposed program.

Leasing program, submittal to President and Congress.

"(2) At least sixty days prior to approving a proposed leasing program, the Secretary shall submit it to the President and the Congress, together with any comments received. Such submission shall indicate why any specific recommendation of the Attorney General or a State or local government was not accepted.

"(3) After the leasing program has been approved by the Secretary, or after eighteen months following the date of enactment of this section, whichever first occurs, no lease shall be issued unless it is for an area included in the approved leasing program and unless it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review pursuant to the provisions of this Act.

(continued)

Review.

"(e) The Secretary shall review the leasing program approved under this section at least once each year. He may revise and reapprove such program, at any time, and such revision and reapproval, except in the case of a revision which is not significant, shall be in the same manner as originally developed.

Regulations.

"(f) The Secretary shall, by regulation, establish procedures for—

"(1) receipt and consideration of nominations for any area to be offered for lease or to be excluded from leasing;

Public notice.

"(2) public notice of and participation in development of the leasing program;

"(3) review by State and local governments which may be impacted by the proposed leasing;

State and local governments, consultation.

"(4) periodic consultation with State and local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on the outer Continental Shelf, including those involved in fish and shellfish recovery, and recreational activities; and

"(5) consideration of the coastal zone management program being developed or administered by an affected coastal State pursuant to section 305 or section 306 of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454, 1455).

Such procedures shall be applicable to any significant revision or reapproval of the leasing program.

Information, availability to Secretary.

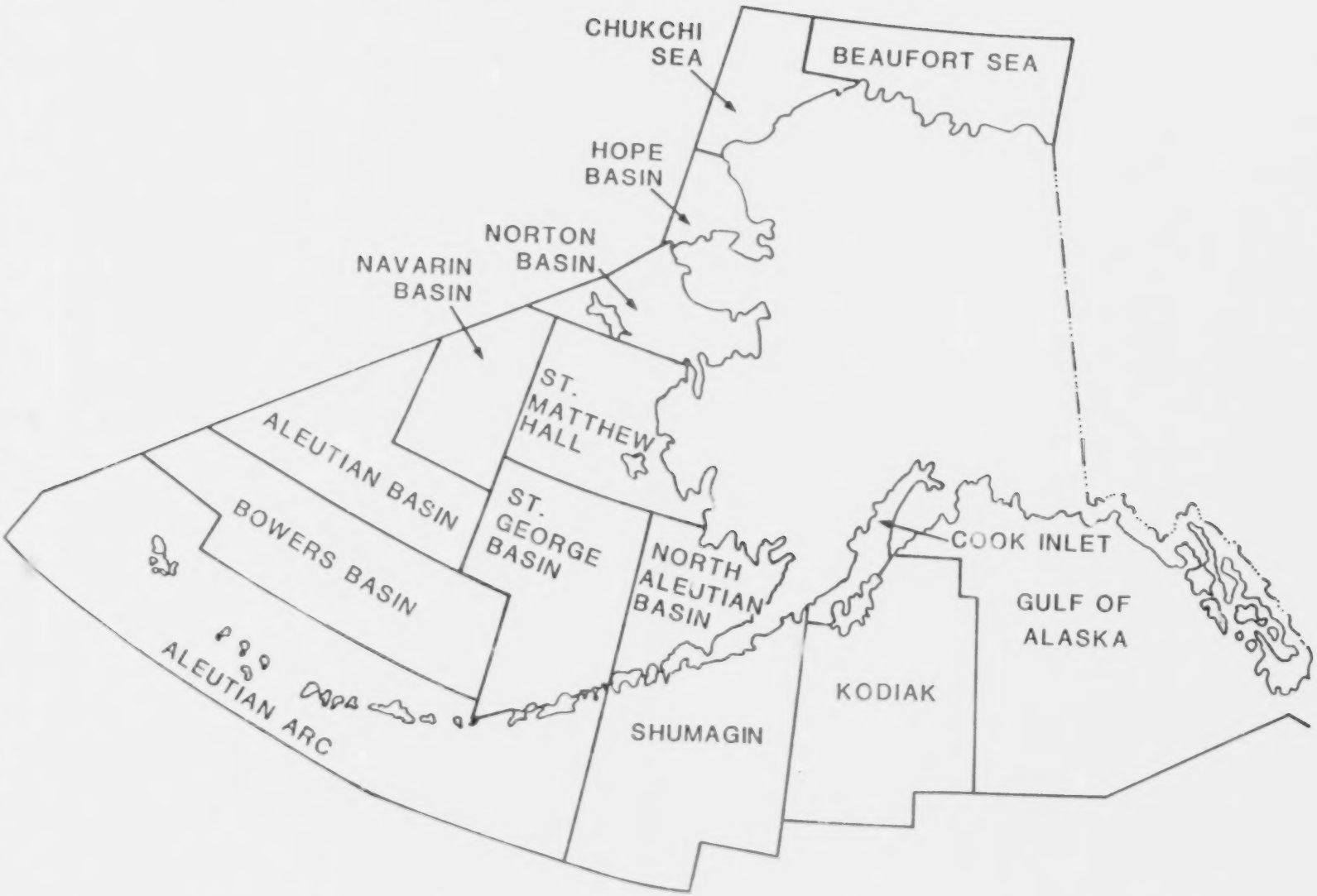
"(g) The Secretary may obtain from public sources, or purchase from private sources, any survey, data, report, or other information (including interpretations of such data, survey, report, or other information) which may be necessary to assist him in preparing any environmental impact statement and in making other evaluations required by this Act. Data of a classified nature provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. The Secretary shall maintain the confidentiality of all privileged or proprietary data or information for such period of time as is provided for in this Act, established by regulation, or agreed to by the parties.

"(h) The heads of all Federal departments and agencies shall provide the Secretary with any nonpriviledged or nonproprietary information he requests to assist him in preparing the leasing program and may provide the Secretary with any privileged or proprietary information he requests to assist him in preparing the leasing program. Privileged or proprietary information provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. In addition, the Secretary shall utilize the existing capabilities and resources of such Federal departments and agencies by appropriate agreement.

I.A.5 Maps Depicting the 26 Planning Areas of the OCS Pursuant to the Decision on the Draft Proposed Program

Map 1

OCS PLANNING AREAS



Map 2

I.B. Framework for Analysis: Planning for an Uncertain Future with Limited Information

Section 18(a) of the OCS Lands Act requires the Secretary to establish a 5-Year OCS Oil and Gas Leasing Program which

> . . . shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval.

Section 18(a) also requires the Secretary to consider a wide range of factors which affect or are affected by OCS oil and gas activities. On the basis of these considerations, the Secretary is to

> . . . select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone [18(a)(3)].

This SID sets forth the information and analysis, both quantitative and qualitative, that has been developed to facilitate the Secretary's consideration and weighing of the potential costs and benefits that could result from leasing in each of the designated planning areas of the OCS. In addition, a final EIS on the new program will be prepared for the Secretary's decision on the third stage of the new program.

Past court rulings (California v. Watt (I) and (II)) have interpreted the provisions of section 18 as requiring the consideration and weighing of the costs and benefits of OCS oil and gas exploration, development, and production through an area-by-area comparison. The benefits are primarily the net economic and energy security benefits from the additional supply of energy to the country from production of OCS oil and gas, as well as the assessment of the oil and gas resources of the OCS. The costs to be considered are a variety of social costs such as potential damages to environmental resources or conflicts with other uses of marine resources. The social costs considered here are those which are generally not included in the economic costs which lessees pay for exploration, development, and production. An analysis of marine productivity and environmental sensitivity has been prepared to serve both as an input and as a complement to the analysis of social costs.

I.B.1. Potential Benefits and Costs

The new OCS Leasing Program is needed for 1987 through 1991 because of the net benefits that can be achieved through production of the oil and gas deposits that may be discovered on the portions of the OCS that are not leased as of 1986. The detailed analysis of benefits and costs and the summation of net social value appear in Part II of this SID.

The MMS estimates that as of January 1987, unleased undiscovered risked OCS oil and gas resources on leasable prospects will have a net economic value of between about $40 billion and about $92 billion ($1987), given a range of starting oil

prices of $19 to $29 per barrel (see Appendix F). The potential net benefits actually realized will depend on many factors: the oil and gas deposits in unleased acreage; their resource and economic characteristics; future conditions in world energy markets; the ways in which oil and gas companies respond in making investments in the OCS; and the actual effects of OCS oil and gas activities on the environment. The potential benefits from unleased acreage can also change in response to changes in the amount of unleased inventory, and the amount of resource information.

Since section 18 requires that the Secretary's selection of a leasing program be based on a consideration of the required technical analyses, it is important to indicate the limitations and implications of the assumptions made in those analyses. Appendix S describes this subject in detail.

A recognition of those limitations has important implications for the formulation of a leasing program, especially with respect to the issue of flexibility.

I.B.2. Limitations on Assessing the Effects of OCS Leasing

It is important in reviewing the materials in this document to recognize several limitations inherent in assessing the effects of OCS leasing and subsequent OCS activities. Because of such limitations, the information assembled for the Secretary's consideration required the development of new methods of analysis, the projection of numerous future events and conditions, and professional judgments on a wide variety of technical parameters.

Section 18(a)(2) speaks in terms of the "Timing and location of exploration, development, and production of oil and gas . . . ." One fundamental limitation on planning for those activities is that the Federal Government can only offer OCS oil and gas leases for purchase by private firms. In OCS lease sales, qualified bidders are given the opportunity to bid on the clearly defined and limited rights to explore, develop, and produce oil and gas which are set forth in the lease, the applicable stipulations, and the large body of applicable laws, regulations, and operating orders. Firms issued leases may then make the additional investments needed to seek, find, and produce oil and gas. The limits of predicting firms' investment decisions thus become, in turn, limits on predicting OCS activities.

The offering of OCS blocks for bids does not in itself cause bids to be submitted or leases to be issued on blocks which are bid upon. In fact, it is very difficult to predict the patterns of bidding and leasing which will occur at a given lease sale. For oil and gas exploration, firms have alternatives to U.S. OCS oil and gas leasing. Firms can lease in the U.S. and foreign onshore markets and in the State and foreign offshore markets. Additionally, the issuance of leases does not necessarily cause investments in exploratory drilling and development. Such investments occur in response to continually changing perceptions about the potential payoffs that might result. In fact, many leased blocks are not drilled because of information gleaned after leasing.

All of the subsequent effects--both costs and benefits--of OCS exploration, development, and production depend upon the patterns of leasing and investment in combination with the the actual location, quantity, and value of the hydrocarbons discovered--if any. Those quantities and values, in turn, can only be estimated in probabilistic terms in advance of lease sales and exploratory investments. Further, discovery of new fields and the amount discovered often bear little relation to the level of leasing and exploration costs, especially in frontier areas. Thus, the very nature of the activity of offering leases and awaiting the results of subsequent investment and exploratory drilling severely limits the precision possible in the prediction of the resultant effects.

I.B.3 Recognition of the Limitations of the Technical Analyses

The precision with which future OCS oil and gas activities can be planned is further limited by the kinds of considerations on which the 5-year program is to be based pursuant to section 18 as interpreted by the court. The factors which section 18(a)(2) requires the Secretary to consider and the balancing which section 18(a)(3) requires the Secretary to perform are the legal bases for the technical analyses which appear in Part II.B of this document. These analyses are, in turn, a key basis for the development of the 5-year program. Notwithstanding the technical aspects of those analyses, the exercise of judgment not reducible to technique is a crucial element in every one of them. This issue is examined in greater detail in Appendix S.

II. Section 18 Analyses

A. National Energy Needs and the OCS Oil and Gas Leasing Program

Section 18(a) of the OCS Lands Act mandates that the OCS Oil and Gas Leasing Program prepared by the Secretary shall be one "which he determines will best meet national energy needs for the five-year period following its approval or reapproval . . . ." The provision that the 5-year program be keyed to national energy needs reflects the first purpose of the OCS Lands Act Amendments:

> Section 102. The purposes of this Act are to--
>
> (1) establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade. . . .

It is also relevant to note here that the Mining and Minerals Policy Act of 1970 (30 U.S.C. 21a) provides that:

> The Congress declares that it is the continuing policy of the Federal Government in the national interest to foster and encourage private enterprise in
>
> (1) the development of economically sound and stable domestic mining, minerals [defined to include oil and gas], metal and mineral reclamation industries, [and]
>
> (2) the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security, and environmental needs . . . .

National Economic and Energy Goals

National economic and energy goals are closely linked. The linchpin is our Nation's continuing dependence on imported oil. In 1984, the United States continued to import about 30 percent of the crude oil which it consumed. The actual disruptions in oil imports which the United States has suffered make clear the nexus of foreign/national security policy and economic policy with respect to the oil import issue. The disruptions of 1973 and 1979 both arose in the international arena and both had substantial recessionary effects on the United States economy. Thus, planning for the future involves consideration of both the national economy and the foreign/national security policy aspects of the oil import issue.

The most recent National Energy Policy Plan, issued by the Department of Energy in October 1983, recognizes this connection. The National Energy Policy Plan sets forth as the general goal of national energy policy the fostering of an adequate supply of energy at reasonable cost. Adequate supply is explained

in the Plan as requiring "a flexible energy system that avoids undue dependence on any single source of supply, foreign or domestic, and thereby contributes to national security. . . [and] further implies freedom of choice about the mix and measure of energy needs to meet our industrial, commercial, and personal requirements." The National Energy Policy Plan recognizes OCS leasing as an important element in the Nation's effort to pursue the assurance of long-term energy supplies.

In examining the way in which OCS oil and gas production can help meet national energy needs, it is appropriate to review the following topics: the role of OCS oil and gas in the United States economy; the current and projected United States demand for energy in general and oil and gas in particular; the current and projected U.S. supply of oil and gas; the prospect for continued dependence on oil imports; the domestic and foreign policy implications of such continued dependence; and the role of OCS leasing in reducing that dependence. The first four points are discussed at length in Appendix F. The summary below reviews those topics and also discusses the last two points.

Oil and gas from the OCS are important resources because they contribute to the production of a substantial volume and variety of goods and services that the American people, as consumers, value.

In addition, OCS oil and gas produced at a cost lower than prices set by the world oil market contribute to the Nation's economic productivity. The greater the amount of OCS oil and gas produced at costs less than world oil prices, the greater is that contribution. Economic productivity is increased by allowing firms a range and sequence of opportunities that will encourage an economically efficient path of investments in OCS exploration and production. In general, this will increase the amount of oil and gas discovered and produced, thus benefiting the economy.

Domestic Energy Supply and Demand

In 1984, the United States consumed 73.73 quadrillion British Thermal Units (Btu) of energy. Oil and gas constituted about two-thirds of that amount. /1

The Nation's production of oil and natural gas liquids peaked in 1970 and dry natural gas production peaked in 1973. The decline in oil production since 1970 reflects the depletion of older fields without the discovery of new reserves sufficient to replace the oil produced. The decline has been cushioned by production from the giant Prudhoe Bay oil field. If it were not for that field, U.S. production would have plummeted nearly 30 percent over the past decade instead of falling by only 5 percent.

The U.S. Department of Energy has projected that total U.S. domestic oil production will decline 1.0 to 1.5 percent per year for the next 10 to 15 years. Total natural gas production is expected to drop also, but more slowly through 1990. /2

/1 U.S. Department of Energy, Annual Energy Review 1984, April 1985, Table 1.
/2 DOE, Energy Projections to the Year 2010, October 1983.

United States Dependence on Imported Oil

Relative to the United States supply of energy from other sources, a substantial percentage of our oil supply is imported. In the 1970 to 1980 timeframe, domestic oil and gas production represented approximately 50 to 60 percent of the total energy supplied to the U.S. economy; imports of oil and gas supplied approximately 11 to 18.5 percent. U.S. Department of Energy projections to the year 2000 indicate that imported oil and gas will continue to supply an estimated 14.6 percent of our total domestic energy in the year 2000. (Imported gas constitutes only 3 percent of the 14.6 percent.) Although this percentage has decreased from a high of 18.5 percent in 1975 and 1980, in absolute terms, imports are projected to increase to 13.4 quad Btu in 1990 (a level which they were at in 1975) and are projected subsequently to rise to 13.6 quad Btu in the year 2000. Domestic production of oil is projected to decrease from 19.5 quad Btu to 17.4 quad Btu in the 1985-2000 timeframe. /3

Potential Contribution of OCS Leasing and Production

Leasing and exploration of OCS oil and gas resources provides an important way of helping to slow the long-term decline of proved domestic hydrocarbons reserves. The hydrocarbons produced from the OCS in Fiscal Year 1984 represented about 12 percent of domestic production of oil and about 25 percent of domestic natural gas production.

In addition to benefiting from the use of domestic oil and gas to fuel the general level of economic activity, the American people benefit in their roles as owners, through the Federal Government, of the resources of the OCS. As owners of OCS oil and gas, the American people benefit from production of any OCS resource costing less to find and produce than the price at which it can be sold (see Appendix F.)

Aside from the effects of a potential supply disruption (discussed below), the importation of foreign oil reduces the economic well-being of the American people. In 1984, the gross cost of importing crude oil and refined petroleum products amounted to over $59 billion. Those imports accounted for almost 50 percent of our balance of trade deficit in that year.

The recent growth in U.S. GNP of about 6.8 percent for 1984 resulted in U.S. oil demand exceeding that of 1983 by about 3.5 percent. /4 The lag in demand for oil is caused in large part by substitution and conservation effects which have yet to run their course.

Means of Pursuing National Energy and Economic Goals

One way to view the national security aspect of OCS production is to see its relation to national economic goals. Disruption of supplies of oil from abroad causes disruption in the production and consumption of goods and reduces economic productivity. This causes decreases in income and increases in consumer price levels. The 1984 Office of Technology Assessment (OTA) report, U.S. Vulnerability to an Oil Import Curtailment, estimates that a

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3 Ibid., Table 3-4. Also see Appendix F.

4 DRI Inc., Energy Review, Volume VIII, No. 4, Winter 1984-1985.

significant disruption of oil imports could result in a reduction of the Gross National Product of 3.5 to 6.2 percent, accompanied by increased unemployment of 1.7 to 2.3 percent (pp. 146-147; see also Appendix F of this SID).

However, most measures to assure that our national energy needs will be met have economic costs. Thus, the economy needs to adjust continually, balancing the costs of those measures against their economic benefits. The OCS leasing program can help to meet both national energy and economic needs by helping to reduce oil imports and providing a source of domestic supply in periods of future disruptions and higher prices.

On the one hand, it is possible that world oil prices in the 1990's will be sufficiently low to render uneconomic many of the oil and gas prospects remaining to be leased on the OCS. On the other hand, oil prices may not decline or remain low for very long. Higher oil prices would increase the number of good prospects for discovery of oil and gas on the OCS. The rate of leasing and investment in exploration would be higher. The resulting production would help the economy use less high cost imported oil, thus increasing its economic productivity (see Part II.B.1).

Over the long run, OCS oil and gas resources will make a contribution to economic productivity if investment and production decisions can adjust quickly to changing world energy markets. An OCS leasing program can help meet the Nation's energy and economic needs by providing opportunities for investments in exploration and development when they are economically timely. Such a program would allow rapid increases in leasing and investment if world oil prices were to increase to higher plateaus while allowing a lower investment and production rate during periods of lower prices. Allowing a quicker shift from imported to domestic oil when oil prices increase reduces the economic costs of abrupt changes in the world oil supply. Ensuring such flexibility in the OCS leasing program can contribute to meeting our national energy needs--but the long lead time for the development of OCS oil and gas resources requires that flexibility be insured throughout the program and well in advance of emergency situations. This point is discussed further at the end of this section.

National Security Concerns Relevant to OCS Leasing

National security considerations clearly point to the need for such flexibility in the OCS leasing program. The continuing dependence of the United States on oil imports for a substantial part of our oil consumption creates a number of national security concerns.

First, the potential for a supply disruption imposes political limits on the flexibility of our foreign/national security policy, including our ability to respond to foreign security threats.

Second, our dependence on foreign nations for so essential a commodity as oil creates the potential for the United States to be drawn into dangerous political and military situations involving those nations.

Third, dependence on oil imports entails dependence on extended supply lines (tanker routes) which present a target for attack and thus add to our defense burden. This added defense burden involves both the deterrence of attacks as well as actual defense in the event of an attack.

Fourth, many other nations, including our allies, are faced with the same set of problems. The restraints on them indirectly but effectively pose further limits on our own national security flexibility. Thus, any improvement in our ability to assist them in meeting their energy needs in turn improves our ability to pursue our own foreign policy/national security goals. The 1983 National Energy Policy Plan, underlines this last point by noting that:

> The overriding concern of our allies to reduce their dependency on imported oil has led to growing reliance on natural gas from the Soviet Union, a new source of vulnerability and concern to our collective energy security and to fundamental United States national security interests.

Fifth, if there were a world oil shortfall, all of our suppliers, including non-OPEC suppliers, might reduce oil shipments to us in order to honor all of their export contracts equitably. Thus, our oil import vulnerability is not limited to our reduced amount of OPEC imports.

Sixth, key weapons systems in the Nation's current arsenal and under development for future use are designed to use liquid hydrocarbon fuel. In Fiscal Year 1983, the armed forces used over 177 million barrels of oil, which was the equivalent of over 58% of OCS oil production in that year. The most secure sources of supply for such fuel are, clearly, domestic sources. This consideration is reflected in section 12(b) of the original OCS Lands Act:

> In time of war, or when the President shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of any mineral [including oil and gas] produced from the outer Continental Shelf.

OCS Leasing in Perspective

The question of how to control our reliance on imported oil over coming decades can be seen as a question of balancing the economic productivity gained by using cheaper imported oil during times when world prices are lower against the potential costs of supply disruptions. Furthermore, it is quite possible that the total U.S. endowment of oil and gas resources will not be sufficient in amount and low enough in cost for production to keep pace with demand through the coming decades during which relatively low cost reserves in the Middle East and elsewhere are depleted. Nonetheless, the OCS oil and gas leasing program can continue to make a significant contribution to meeting national energy needs.

In order to understand the contribution which OCS oil and gas leasing can make to long-term energy supplies, it is useful to review some of the other efforts and proposals which have been made to reduce our vulnerability to oil supply disruptions. While these approaches have a great deal to offer, they nonetheless have limitations which call for the kind of contribution which the OCS leasing program can make to the pursuit of national energy goals. These approaches include: the creation of the Strategic Petroleum Reserve; the diversification of supply; the concept of developing synthetic oil replacement capability; and reliance on alternative energy sources.

--The Strategic Petroleum Reserve

At its current level of about 450 million barrels, the Strategic Petroleum Reserve (SPR) can substitute for about 141 days of oil imported at current rates of supply and demand. The SPR's greatest usefulness is in blunting supply cuts and the resultant price spikes in the short-run. In the case of a disastrous reduction of oil supply over a sustained period, the SPR--even if filled to its ultimate capacity, once envisioned as one billion barrels, but now set at three-quarters of a billion barrels--would prove of limited usefulness. While such a disaster is not on the immediate horizon, it cannot be dismissed as a possibility. After all, the West's supply of oil is disproportionately dependent on the oil production of a handful of nations whose political future cannot be said to be assured.

--Diversification of Sources of Supply

The diversification of sources of supply which the United States and, to a lesser extent, its allies, have been able to achieve presents the prospect of significant protection against the disruption of oil supplies from the Middle East. Yet its potential to insulate the United States from vulnerability to such disruptions also has limits. First, it could well be that during a significant supply disruption, remaining suppliers might ration the added supplies which they are capable of providing so as to treat all of their customers equitably. Second, under the auspices of the International Energy Agency, the United States and many of its allies are obliged to share oil in the event of a major disruption of oil supplies. That sharing system has never been put to a real test, however. Furthermore, by relying on other nations to share their limited supplies with us in order to meet our great oil consumption demands, we could well strain our relations with the nations on which we relied for such sharing and with those with whom we would be competing for supplies. Thus, the less we need to depend on such sharing agreements, the better off we would be in terms of both certainty of supply and relations with other nations.

--Oil Replacement Capability

Another useful concept is the development of oil replacement capacity--i.e., the capacity to deploy technologies and strategies which minimize the effects of a long-term oil supply shortfall. Again, however, an oil replacement strategy does not exhaust the range of useful responses to the problem posed by our vulnerability to the disruption of oil supplies from abroad. Increased domestic supplies of hydrocarbon fuel still have an important role to play in responding to an oil import shortfall. Indeed, the OTA study on oil replacement (cited above) includes a discussion of the desirability of the deregulation of the price of natural gas so as to increase its supply (at pp. 27-28, 30).

--Alternative Energy Sources

Several energy sources other than oil and gas are expected to be used in this Nation during the remainder of this century and the first quarter of the next. These sources include coal, hydroelectric, nuclear, oil shale, tar sands, and geothermal energy. Nonconventional forms such as wind, solar, and converted biomass energy may also be used to a much lesser extent. Coal will probably be the most heavily used alternative source of energy, followed, in order, by hydroelectric, nuclear, and geothermal energy (see Appendix F).

Notwithstanding use of the several alternative forms of energy discussed above, the U.S. Department of Energy projects that about 38.7 percent of the Nation's energy demand in the year 2010 will be met by oil and gas. Nearly 40 percent of this needed oil and gas is projected to be imported. /5

By providing opportunities to increase our domestic supplies of oil and gas, the OCS leasing program provides an important--and less costly--contribution to energy security, in addition to the three strategies described above. Leasing of the OCS also provides supplies which are available over the long-term.

Information Benefits

Information benefits are another type of benefit from OCS leasing, exploration, and development. Information benefits are the benefits to the Nation--beyond economic benefits--of added information about the extent of oil and gas resources on the OCS.

The generation of information benefits is one of the specified purposes of the 1978 OCS Lands Act Amendments. Section 102(9) of the Amendments states that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time." It is of the nature of oil and gas resource assessment that only drilling can confirm the existence and size of a deposit. On the OCS, drilling for oil and gas is essentially tied to leasing and thus to the 5-year leasing program.

As in the case of production, the contribution to the overall picture made by any particular lease may be small, but without the small pieces, the overall picture cannot be created. Of all the small pieces, the first well in an area generally provides the most information. Where the existence of commercial accumulations of hydrocarbons has not been demonstrated, there is usually a high degree of dependence among estimates of resources on prospects. In these cases, the information generated by exploration on a given prospect generally sheds a great deal of light on the resource potential of the surrounding acreage. /6

The estimated size of the resource base of the OCS has major implications for the country's energy and national security policies. Clearly, if U.S. oil and gas resources were very great or very limited, the implications for our foreign policy would be very different. While the resources potential of the U.S. is estimated to be somewhere between those two extremes, it is best for the Nation to know just where it stands.

The Department of State is also particularly concerned with estimates of OCS oil and gas resources regarding international boundary negotiations with neighboring nation-states concerning jurisdiction over those resources. Such negotiations are ongoing concerning several planning areas.

The Department of Energy has made explicit use of estimates of undiscovered OCS oil and gas resources in developing its report, Replacement Costs of Domestic Crude Oil (1985), which is designed to aid in planning for fossil energy research and development.

/5 U.S. Department of Energy, Energy Projections to the Year 2010, October 1983, Table 3-5.

/6 See, for example, MMS, Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984, (OCS Report MMS 85-0012), p. 22.

The OTA Report on Oil and Technologies for the Arctic and Deepwater (May 1985) provides a useful summary of this issue in stating that

> If Congress wishes to pursue the objectives of the OCS Lands Act, it is important that the oil and gas industry have access to Federal offshore lands to more accurately determine the resource potential of frontier areas. A "second-round" leasing strategy may also be needed to assess the extent of smaller offshore reservoirs that could cumulatively contribute to the Nation's energy security [p. 5].

The OTA report also states that

> Accurate knowledge of the resource potential of the Nation's offshore areas is critical to overall energy planning and to making decisions about the offshore leasing program and alternative energy programs [p. 11].

That report highlighted the decline from previous levels of the most recent MMS OCS estimates of oil and gas resources offshore Alaska and in the Atlantic and examined its implications for U.S. energy policy. Some interpretations of the latest data have focused on that decline as supporting policies of energy conservation and alternative energy research. Others have gone so far as to suggest that somehow the new data means that OCS leasing, exploration, and development are not worth pursuing--even for the substantial economically recoverable resources which are still estimated to exist. The Department of the Interior--complementing the first view and opposing the second--emphasizes the substantial contribution which OCS leasing, exploration, and development will continue to make in terms of net social value, national security, and information benefits. For only through actual exploratory drilling can the truth be determined about the presence of oil and gas.

The Long-Term Role of OCS Leasing and Production

The long-term character of OCS production is matched by the long-term character of the planning and development which precedes production. Holding an OCS lease sale is the fruit of years of public and private planning. Once OCS acreage is leased, initial production can take another 5 to 15 years. Thus, the next leasing program needs to be considered as a step in meeting domestic supply requirements of the late 1990's and the first quarter of the 21st century.

The consequence of the long-term character of OCS development is that decisionmaking about it should not be guided by the trend of the day. Leasing of the OCS is unusually vulnerable to short-term phenomena which can disrupt it in ways that can be made up only at substantial cost in time and opportunity. Public policy concerning OCS leasing should, therefore, be guided by a steady, long-term perspective on the potential seriousness of the risks involved in oil supply disruptions, their unpredictability, and the long lead-times necessary to make OCS production available for use. Without the assurance that OCS leasing policy will remain firm, industry would likely be reluctant to invest the huge sums required to develop OCS resources.

What this means can be illustrated by examining the argument that potential oil and gas resources be withdrawn from leasing in certain areas and saved as a "reserve" for use in a national emergency. In practice, however, the only way in which potential oil and gas resources can constitute a useful reserve in case of an emergency is if they are not withdrawn from the normal course of exploration and development through which drilling can locate and delineate the reserve deposit and the necessary production infrastructure can be put in place.

II.B. Planning Area Analyses

Pursuant to California v. Watt (II), the following comparisons of planning areas provide a basis for considering whether there is any categorical impediment to OCS leasing in any planning area. These analyses also provide input for the discussion of the equitable sharing of developmental benefits and environmental risks in Part II.C. and the discussion of balancing in Part II.D.

The July 1984 request for comments on the development of the new program divided the entire OCS into 24 planning areas. The March 1985 Draft Proposed Program divided the OCS into 26 planning areas. First, it reconfigured the planning areas offshore California from two (Southern California and Central/Northern California) to three (Southern California, Central California, and Northern California). Second, the southern part of the South Atlantic planning area was made the Straits of Florida planning area. This reconfiguration is incorporated in the section 18 analyses and the schedule options for Secretarial decision on the Proposed Program.

The planning areas analyzed are discussed in the Federal Register Notice describing the Draft Proposed Program (see Appendix M). At this Proposed Program stage, four planning areas (Aleutian Basin, Bowers Basin, St. Matthew-Hall, and Aleutian Arc) have been deleted from further consideration because they were estimated to contain negligible resources.

For this SID for the Proposed Program, the following refined section 18 analyses have been prepared. A final version of these analyses will be prepared for the decision on the Proposed Final Program.

To provide for comparability of the oil and gas resource value estimates among the planning areas the following general approach was employed:

1. All OCS oil and gas resources estimated to be worth acquiring by private industry under specified economic conditions were assumed to be leased as of January 1987 in each planning area. Exploration, development, and production would then follow according to a scenario characteristic of the planning area. The results for starting prices of oil at $19 and $29 per barrel are presented in Table 2.

2. Net present value estimates were calculated for a risked mean resource estimate and an economic base case scenario assuming a July 1984 starting price of oil of $24 a barrel, a 1-percent real annual price growth rate, and an 8 percent discount rate. Sensitivity analyses were conducted around the risked mean resource estimate

which allowed for variations in the base case assumptions for the starting price of oil, the annual average growth in oil prices, and the discount rate. The results for starting prices of oil at $19 and $29 per barrel are presented in Table 3. The remaining sensitivity calculations are included in Appendix F.

Section 18 analyses have been performed on a planning area basis. It is important to note that the MMS aggregate estimates of resources and net economic value, as well as industry rankings for various planning areas, do not distinguish between areas in which high-valued resources and industry interest are concentrated in a portion of a planning area and those in which low-valued resources and industry interest are widely distributed throughout the planning area. It should also be noted that the presale process provides ways of adjusting the size of the area offered in lease sales in order to accommodate these differences among areas. The presale process is discussed further in Part III and Appendix P.

II.B.1. Estimates of Hydrocarbon Resources and Economic Benefits

To facilitate the Secretary's consideration of the potential for oil and gas discovery and the resulting contribution to the Nation's energy and economic needs that could result from leasing in each of the OCS planning areas, estimates of the oil and gas resources and their net economic values were made. Two major improvements were made over the estimating procedures used in the 1982 program formulation:

1. The estimation of oil and gas resources in each area was based upon an extensive evaluation of an inventory of identified unleased prospects rather than upon calculations employing the aggregate volumes of oil and gas likely to be found (used in the 1982 analysis).

2. The estimates of resources and net economic values in each area were based upon a wider range of characteristics (e.g., variation in prices and discount rates) that influence the economics of various prospects than was the case in the 1982 analysis.

These improvements make it possible for the Secretary to consider in more detail the aspects of each planning area that characterize its potential for yielding oil and gas discoveries and economic benefits. The economic measure

of the benefits which the Nation can realize from OCS oil and gas exploration and development is the net economic value of the hydrocarbon resources. The net economic value of an oil and gas deposit measures the difference between the revenues from the sale of oil and gas produced and the costs of exploration, development, production, and transportation--both costs and revenues being appropriately discounted to present value. Estimates of net economic value take into account the probabilities of the various events that affect the resource and economic outcomes of investment in an unexplored prospect. Net economic value is also a measure of the benefits to the economy in the form of cash bonuses, royalties or profit share payments, rental fees, taxes, and after-tax business profits. The sum of the amounts expected to be captured in these forms is equal to the difference between expected production revenues and costs (see Appendix F).

a. Hydrocarbon Resources

Three different categories of hydrocarbon resource estimates have been made for each of the planning areas of the OCS:

1. conditional economically recoverable oil and gas resources;
2. risked economically recoverable oil and gas resources; and
3. leasable oil and gas resources.

Table 1 (derived from Table 5 of Appendix F) contains the range of conditional resource estimates of each of the OCS planning areas, indicating the great variability in their magnitude. Due to the inherent uncertainty of estimating undiscovered resources, especially in frontier areas, a range of estimates is shown in Table 1 of the SID. The 95 percent case for conditional estimates of both oil and gas reflects a low case where there is 95 percent probability of that amount or more occurring. The high case reflects a 5 percent probability of that amount or more occurring. A conditional mean estimate is the average amount you would expect to find if at least one of the prospects in the area contained economically recoverable accumulations of hydrocarbons and if all of the prospects modelled were drilled. The conditional resource estimates assume that hydrocarbons will be present in some of the planning area prospects. They do not take into account the possibility that the area may not be hydrocarbon prone; this consideration is taken into account in determining the risked economically recoverable resources in a planning area (see Table 6 of Appendix F).

For each of the 2400 geologic prospects identified by MMS on the OCS, a resource estimating model generated a projection of the risked economically recoverable resources. Procedurally, the model first generated a conditional distribution indicating the probability of finding different amounts of commercially producible and nonproducible hydrocarbons given that at least some of the identified prospects contained hydrocarbons.

Table 1

Ranges of Conditional Estimates of Unleased Undiscovered
Economically Recoverable Oil and Gas Resources as of March 1985 /1

Planning Area	Conditional Oil (BBO) /2			Conditional Gas (TCF) /3		
	95% Case	Mean Case	5% Case	95% Case	Mean Case	5% Case
Central Gulf of Mexico	.95	2.66	4.97	7.57	20.64	36.53
Western Gulf of Mexico	.45	1.69	3.31	7.23	22.61	41.05
Eastern Gulf of Mexico	.03	.36	1.48	.04	1.63	8.88
Southern California	.61	1.26	2.08	0.97	1.93	2.98
Northern California	.15	.42	.76	1.17	1.86	2.48
Central California	.18	.56	1.01	.29	.79	1.38
Washington-Oregon	.04	.18	.54	2.20	3.26	3.62
South Atlantic	.34	.82	1.46	6.30	15.45	27.56
Mid-Atlantic	.07	.24	.51	1.39	4.21	8.18
North Atlantic	.10	.26	.43	1.98	5.06	9.03
Straits of Florida	.01	.04	.12	.20	1.04	3.79
Navarin Basin	1.81	3.28	5.09	2.34	4.26	6.75
Beaufort Sea	.11	.65	1.66	.52	2.98	6.39
St. George Basin	.37	1.12	1.98	3.42	9.24	18.04
Chukchi Sea	.96	2.68	4.88	5.06	15.10	27.71
Gulf of Alaska	.12	.49	.86	1.60	8.00	18.26
North Aleutian Basin	.08	.36	.76	.56	2.62	5.25
Norton Basin	.05	.28	1.02	.31	1.55	4.26
Kodiak	.04	.15	.26	.58	2.92	7.13
Hope Basin	.13	.17	.40	.53	1.81	4.12
Shumagin	.05	.05	.09	.49	1.42	2.65
Cook Inlet	.03	.18	.40	.04	.32	.69

/1 See Appendix F, Table 5
/2 Billions of barrels of oil
/3 Trillion cubic feet

Setting commercially nonproducible amounts of resources at zero with its associated probability, the mean of this revised distribution of producible resources was obtained. When this mean producible amount was multiplied by the marginal probability that the prospect contained hydrocarbons, the risked economically recoverable resources for the prospect was calculated.

The term economically recoverable oil and gas resources, as used throughout this analysis, is a measure of those resources found in sufficient quantities such that the revenues produced cover the costs of development and production, royalties and taxes, while allowing for a normal rate of return. The estimates of both conditional and risked economically recoverable resources do not take into account costs incurred in searching for oil and gas, primarily exploration expenses. As a consequence, in estimating at the time of sale the net economic value of prospects containing positive amounts of economically recoverable resources, some prospects were found not only to have negative private values but also negative net economic values as well. Such prospects would not receive a bid based on this assessment of the present value. In order to provide the Secretary with aggregate estimates of oil and gas resources and net economic values likely to be influenced by decisions relating to the next 5-Year Program, a new category of resources called leasable resources has been defined.

Leasable resources are estimated as follows. An assessment is conducted of each prospect to determine its (risked) economic value at the time of sale to both the lessee and to the Nation as a whole. If the private value (after tax net present value), as estimated by MMS, is found to be greater than zero, then the economically recoverable resources associated with the prospect are considered leasable. If the private value of the prospect is zero or less, then the entire amount of the prospect's economically recoverable resources are deemed to be unleasable at the time of sale for the given economic assumptions.

Thus, the estimate of leasable resources in a planning area is the sum of economically recoverable resources associated with prospects calculated by MMS to be worth acquiring, i.e., they have positive private values. The estimates of leasable resources as of January 1987, are somewhat understated because resources which may become leasable after January 1987, due to real oil price growth, are not factored into the estimates.

The resource estimates were prepared using assumptions (prices, price growth, discount rates, etc.) developed for the 5-Year Program analyses. These estimates may not reflect the economic parameters and assumptions used for upcoming sale specific analyses; and therefore should not be applied to any sales scheduled prior to the beginning of the new 5-Year Program (January 1987).

Table 2 contains the estimates of leasable resources for each of the planning areas for prices reflecting a low case of $19 per barrel, and a

Table 2

Variation in Risked Estimates of Unleased Undiscovered /1
Oil and Gas Resources Projected to be in
Leasable Prospects ("Leasable Resources") as of January 1987 /2
(from $19 to $29 per barrel 1984 starting prices)

Planning Area /3	Estimated Risked Oil and Gas Resources (Millions of barrels of oil equivalent (BOE)) Starting Prices @ $19/bbl	@ $29/bbl
Central Gulf of Mexico	4,603	4,662
Western Gulf of Mexico	4,491	4,630
Southern California	1,046	1,264
Navarin Basin	178	785
South Atlantic	392	730
Eastern Gulf of Mexico	331	470
Northern California	281	414
Central California	320	405
Beaufort Sea /4	*	308
Mid-Atlantic	88	184
St. George Basin	*	160
Washington-Oregon	46	56
North Atlantic	35	74
Straits of Florida	6	6
Chukchi Sea /4	*	400
Gulf of Alaska	*	28
North Aleutian Basin	*	16
Norton Basin	*	12
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than 0.5 million BOE).

/1 Risked oil and gas resource estimates are obtained by multiplying the conditional mean resource estimate by the marginal probability of the presence of commercial accumulations of hydrocarbons (see Appendix F).

/2 Resource estimates exclude those resources expected to be leased in upcoming sales scheduled to be held before the start of this 5-year program. Leasable resources are those which, prior to exploration, are expected to bring positive net benefits to the lessees after deducting royalties, rentals, and taxes. After adjusting for transportation costs and crude oil quality expected in each OCS region, January 1987 landed BOE price estimates were computed assuming a 5 percent annual inflation rate and a real oil price increase of 1 percent per year. An annual real discount rate of 8 percent was used to determine 1987 discounted value of all costs and benefits. All calculations of net economic value and social costs in this SID and its appendices were based on these assumptions unless otherwise specified (see Appendix F).

/3 The planning areas are ordered by "leasable resources" at $24/bbl.

/4 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

high case of $29 per barrel--as applied to the risked mean resource estimates.

Resource estimates were revised to take into account sales appearing on the current schedule through January 1987. As Table 2 shows, the Central and Western Gulf of Mexico areas are estimated to have more resource potential in acreage unleased as of 1987 than all the other planning areas combined. The Southern California planning area ranks next with considerably more resources than any other planning area. Significant changes in the resources occur in certain frontier planning areas as the starting oil price assumption moves from $19 to $29 per barrel of oil because of the high development costs in these areas.

Past and projected leasing in the 1982-1987 period, unpromising exploration results in many areas to date, and lower price expectations have substantially reduced the resource potential remaining to be leased, as compared to the situation anticipated in 1982. This is especially the case in areas previously believed to have high potential, such as the Beaufort Sea and North and Mid-Atlantic areas which were ranked relatively higher in the 1982-1986 program. Most of these areas could show increased potential assuming higher price expectations, positive results from exploration, or additional seismic data evaluation. This is also true of areas where there has been little or no exploration.

b. Economic Benefits

For each planning area, estimates were made of the net economic value of the prospects containing leasable resources. For comparative purposes on a planning area basis, these estimates were based on the assumption that all leasable prospects were acquired by private industry at the beginning of 1987 and subsequently explored, developed, and produced over time periods typical of each area. This approach was upheld by the court in California v. Watt (II) (see Appendix F).

The base case estimates of net economic value for each of the planning areas' leasable oil and gas resources assumed a $24 per barrel starting price of oil with a sensitivity of plus and minus $5 per barrel, that is, a variation from $19 to $29 per barrel. Price sensitivity results were incorporated into the net economic value estimates to reflect the great uncertainty in projecting future oil prices. This sensitivity analysis shows how the potential benefits of OCS development depend upon future prices. For example, the $19 and $29 price cases in 1984 correspond to values of $27 and $41 per barrel in year 2010 (as expressed in 1987 dollars).

It should be noted that this analysis reflects the sensitivity of net economic value to changes in the price assumptions only, and does not incorporate the affects of geologic and economic resource uncertainty conveyed by the ranges of resource estimates. The SID does not provide ranges which reflect both sources of uncertainty combined. It should also be noted that while the variation in net economic value is keyed to alternative starting oil prices, the resulting variation of net economic value is a kind of surrogate for other sensitivity measures which have not been performed (e.g., with respect to resource estimates and the variability of oil and gas prices within the range depicted in Figure 1).

The $19 and $29 per barrel starting prices of oil are expressed in July 1984 dollars, which was when this analysis began. It was subsequently adjusted to January 1987 price levels by assuming a 1 percent real annual increase in the price of oil and a 5 percent inflation rate applied for 2 years beginning in January 1985. After January 1987, prices were assumed to increase at a 1 percent real annual rate of growth. Sensitivity analyses of the net economic value estimates were conducted to demonstrate the variability of the estimates to changes in the price growth rate (at zero percent and 2 percent annually) and at a 6 percent to 8 percent discount rate assumption (see Table 13 of Appendix F). As can be seen from the sensitivity analysis, the variation in net economic value estimates is even greater when considering these further changes in assumptions.

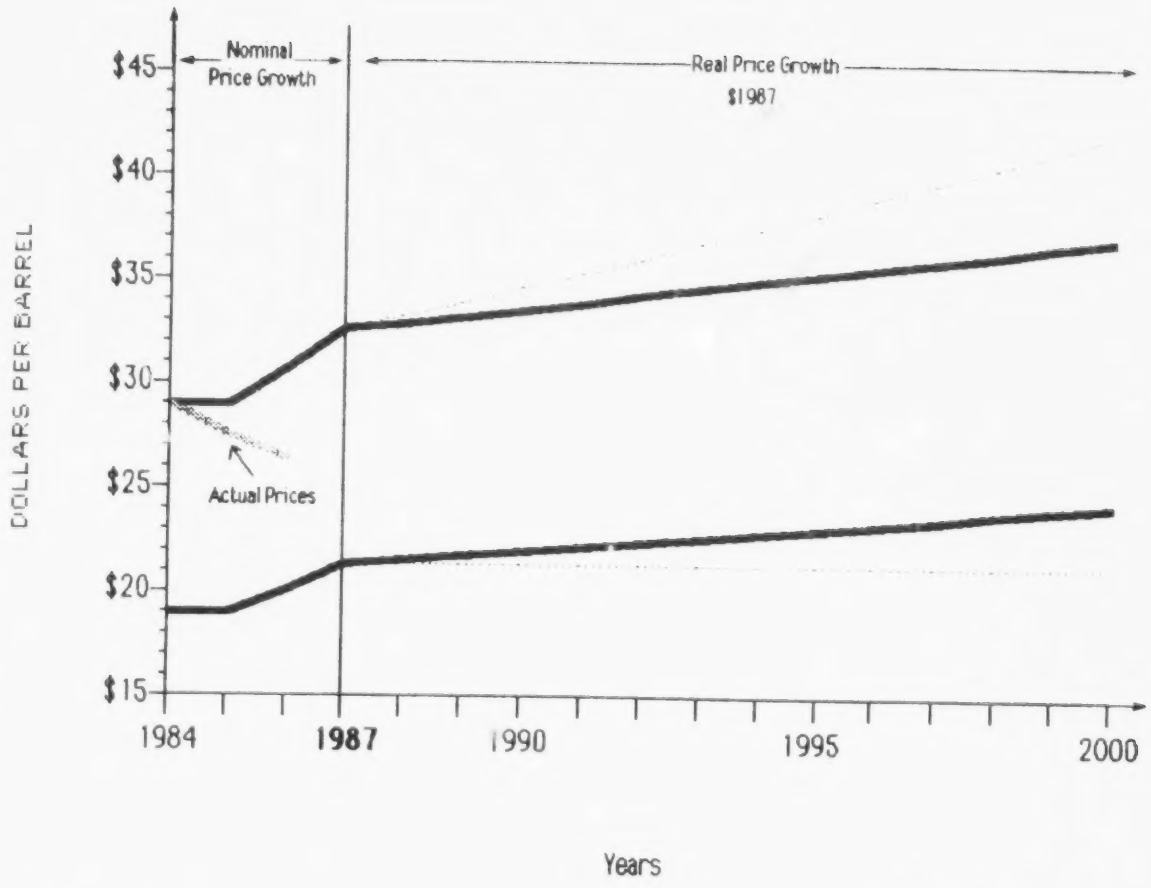
Figure 1 graphically approximates the variation in prices which were considered in the development of the leasable resources and net economic value estimates (limited to the year 2000 for ease of display). As can be seen from this graph, actual prices through July 1985 are declining. As explained in Appendix F, this is one reason that the variation in price estimates were adjusted downward, from $34 to $24 per barrel in the Draft Proposed Program to $29 to $19 per barrel for this Proposed Program. The high and low price cases considered for the Proposed Program (depicted by the bold lines in Figure 1) were selected to cover the range of oil prices which are projected to exist during the time of exploration and development of resources expected to be leased during the 5-Year Program of 1987-1991.

Table 3 shows the variation of net economic value estimates (1987 dollars) indicating the great variability in the values over a $10 price spread, Table 5 shows these same results on a per barrel basis. The high case estimates for certain Alaska areas in Table 3 indicate the profitability of oil and gas with the higher price scenario. The sum of the net economic value estimates show a potential increase in benefit to the economy of $50 billion as one moves from the $19 per barrel case to the $29 per barrel case.

In addition to the total net economic value estimates for leasable resources in each planning area, estimates were prepared showing the distribution of these undiscovered resources in each area by dollar categories of the net economic value. Table 4 shows the leasable oil and gas resources in each of three net economic value categories: $0.00 to $3.00; $3.00 to $6.00; $6.00 to $10.00 per barrel for the low and high starting price cases.

FIGURE 1

OIL PRICE SCENARIOS FOR THE 5-YEAR OCS LEASING PROGRAM



The variation in oil prices used to estimate leasable resources and net social value for the 5-Year OCS Leasing Program is depicted by the bold lines. The $19 and $29 starting prices reflect a range of weighted average FOB prices of U.S. imports of oil at the time when the analysis began in 1984. These prices are then adjusted for real price growth and inflation (nominal price growth) to arrive at January 1987 starting prices of oil for the 5-Year Program. Thereafter, prices are adjusted assuming a 1% annual real price growth. The broken lines reflect a wider range of real price growth assumptions for sensitivity analysis.

Table 3

Variation in Estimated Net Economic Value
of Unleased Undiscovered Oil and Gas Resources /1
in Leasable Prospects as of January 1987 /2
(from $19 to $29 per barrel 1984 starting prices)

Planning Area /3	Estimated Net Economic Value (Millions of 1987 Dollars) Starting Prices @ $19/bbl	@ $29/bbl
Central Gulf of Mexico	17,860	35,245
Western Gulf of Mexico	14,506	31,299
Southern California	3,975	9,088
South Atlantic	839	3,022
Central California	765	2,649
Northern California	910	2,463
Eastern Gulf of Mexico	675	2,379
Navarin Basin	121	2,591
Mid-Atlantic	198	723
Washington-Oregon	207	454
Beaufort Sea /4	*	678
St. George Basin	*	464
North Atlantic	85	258
Straits of Florida	14	33
Chukchi Sea /4	*	596
Gulf of Alaska	*	33
North Aleutian Basin	*	20
Norton Basin	*	20
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than 0.5 million of $1987, using base case assumptions).

/1 Net economic value is the revenue obtained by the sale of oil and gas less the exploration, development, production, and transportation costs necessary to bring the oil and gas to market. Net economic value for upcoming sales scheduled to be held before the start of this 5-year program is not included in these estimates.

/2 See footnote 2, Table 2, for price and discount rate assumptions.

/3 The planning areas are ordered by net economic value at $24/bbl.

/4 Net economic value calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

Table 4

Distribution of Risked Developable Resources by Net Economic Value Category Showing Variation by Starting Oil Prices /1
(Millions of barrels of oil equivalent (BOE))

	Leasable Resources /3						Developable but/4 not Leasable	
	Net Economic Value ($1987 per barrel)							
	$6.00 to $10.00		$3.00 to $6.00		Below $3.00			
nning Area /2	@$19/bbl	@$29/bbl	@$19/bbl	@$29/bbl	@19/bbl	@$29/bbl	@19/bbl	@29/bbl
ıtral Gulf f Mexico	*	4,539	4,300	123	303	*	577	518
tern Gulf f Mexico	*	4,087	2,644	543	1,847	*	139	*
thern alifornia	*	790	617	474	429	*	554	336
th Atlantic	*	*	*	462	392	268	498	160
tral alifornia	*	129	92	276	228	*	140	55
thern alifornia	*	186	151	228	130	*	169	36
tern Gulf f Mexico	*	211	31	206	300	54	249	109
arin Basin	*	*	*	516	178	269	912	305
-Atlantic	*	*	*	88	88	96	712	616
hington-regon	*	46	46	10	*	*	104	94
ufort ea /5	*	*	*	*	*	308	460	152
George asin	*	*	*	*	*	160	380	220
th Atlantic	*	13	13	22	22	28	315	276
aits of lorida	*	*	*	6	6	*	14	14
kchi Sea /5	*	*	*	*	*	400	540	140
f of Alaska	*	*	*	*	*	28	150	122
th Aleutian asin	*	*	*	*	*	16	90	74
ton Basin	*	*	*	*	*	12	40	28
iak	*	*	*	*	*	*	30	30
e Basin	*	*	*	*	*	*	10	10
nagin	*	*	*	*	*	*	10	10
k Inlet	*	*	*	*	*	*	10	10

* Negligible (estimated to be less than 0.5 million BOE).

Note that where leasable resource estimates appear to decline at higher prices, the resources have actually been reclassified into higher net economic value categories.

The planning areas are ordered by net economic value at $24/bbl.

See footnote 2 to Table 2. The data in Table 4 are taken from Table 7 in Appendix F.

Developable resources are those that are profitable for a lessee to produce, given that they have already been discovered.

Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

These disaggregated estimates of resources allow more detailed consideration of the economic characteristics of the oil and gas resources within each area. For example, the Western and Central Gulf of Mexico areas have substantial resource potential in the highest net economic value categories as well as a small amount in the lower value category. This means that there will be a substantial number of good investment opportunities to be found there even with a significant drop in the price of oil. (Table 8 in Appendix F substantiates this). The distribution of the resources in the low value category in planning areas such as the Navarin Basin, St. George, and Beaufort Sea make these areas highly susceptible to a drop in oil prices.

The three California areas, the Eastern Gulf of Mexico, and Washington-Oregon, also have significant resource potential in the highest value categories. The estimates of resource potential in the upper value categories means that leasing and investment in exploration will be worthwhile even at prices as low as the $19 per barrel case price. (See Table 8 of Appendix F.)

Estimates were also made of the effect of delaying leasing and the investments leading to production in each area. As explained in Appendix F, if oil prices are expected to increase at a constant annual rate, highest cost, lowest valued prospects are expected to increase in net economic value enough to yield benefits from delays while the lowest cost, highest valued prospects are expected to decrease in net economic value if investments are delayed. Estimates of the simple average annual dollar changes in net economic value per barrel were calculated assuming that real oil prices increase at 1 percent and 2 percent per year.

Table 6 of the SID displays the results of applying the per barrel delay costs for the $19 and $29 per barrel price cases to the leasable resources estimated for each planning area. The results yield estimates of the average annual costs of delaying leasing for all leasable resources in each planning area. For all cases, in virtually all planning areas (except for the Navarin Basin in the low price case), a delay in leasing would be expected to result in an overall decline in net economic value for the planning area. Comparing the results in Table 6 with those in Table 4 demonstrates that areas with more low cost, high valued resource prospects such as the Gulf of Mexico and Pacific areas tend to have higher costs of delay. Areas with predominantly lower valued resource prospects have lower delay costs.

To test the sensitivity of the delay analyses to a change in the discount rate assumption, a lower rate--6 percent--was also examined. The results are displayed in Table 9 of Appendix F.

In assessing the results of the analysis, it should be noted that there is a high degree of uncertainty surrounding resource estimates, costs, technology, economic parameters, and therefore each area's net economic

Table 5

Sensitivity of Net Economic Value (NEV) to the Starting Oil Price/1

Planning Area	Net Economic Value ($/BOE) Starting Price @19/bbl	Starting Price @$29/bbl
Central Gulf of Mexico	3.88	7.56
Western Gulf of Mexico	3.23	6.76
Southern California	3.80	7.19
South Atlantic	2.14	4.14
Central California	2.39	6.54
Northern California	3.24	5.95
Eastern Gulf of Mexico	2.04	5.05
Navarin Basin	0.68	3.30
Mid-Atlantic	2.25	3.93
Washington-Oregon	4.50	8.11
Beaufort Sea	0	2.20
St. George Basin	0	2.90
North Atlantic	2.43	3.49
Straits of Florida	2.27	5.49
Chukchi Sea	0	1.49
Gulf of Alaska	0	1.19
North Aleutian Basin	0	1.28
Norton Basin	0	1.66
Kodiak	0	0
Hope Basin	0	0
Shumagin	0	0
Cook Inlet	0	0

/1 Data taken from Appendix F, Table 8.

Assumptions: Annual Oil Price Change: 1 percent
Discount Rate: 8 percent

Table 6

Simple Average Annual Change in Net Economic Value for Leasable Resources from a One-Year Delay in Leasing, Showing Variation by Starting Oil Price /1

Planning Area	Net Economic Value (Millions of 1987 Dollars) Starting Price @ $19/bbl	Starting Price @ $29/bbl
Central Gulf of Mexico	-1,013	-2,145
Western Gulf of Mexico	-764	-1,852
Southern California	-220	-493
South Atlantic	-39	-153
Central California	-29	-142
Northern California	-48	-133
Eastern Gulf of Mexico	-26	-136
Navarin Basin	+2	-86
Mid-Atlantic	-9	-35
Washington-Oregon	-12	-22
Beaufort Sea	*	-31
St. George Basin	*	-19
North Atlantic	-4	-12
Straits of Florida	-1	-2
Chukchi Sea	*	-36
Gulf of Alaska	*	-1
North Aleutian Basin	*	*
Norton Basin	*	*
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than .5 million of $1987, using base case assumptions).

/1 Data from Appendix F, Table 9.

Assumptions: Annual Oil Price Change: 1 percent
Discount Rate: 8 percent

value. These estimates reflect a detailed, thorough, quantitative analysis by MMS professionals, but the estimates are subject to significant limitations (see Appendix F and Appendix S). Prudent use of these estimates would be limited to drawing general distinctions among planning areas which have estimates which differ by an order of magnitude or more. The estimates should be viewed as relative approximations rather than absolute numbers.

II.B.2 Estimated Social Costs

Background

In compliance with California v. Watt (I) and (II), a quantitative analysis was made of some of the potential social costs which might be associated with development of the recoverable hydrocarbon resources in each of the OCS planning areas. While the estimated social costs are associated with the development of the resources of each of the planning areas, they should be viewed as costs to the Nation as a whole. This is so since not all of the costs resulting from development of the resources in a planning area are necessarily borne by the residents living near the area.

Focusing on costs to the Nation as a whole is also necessary to provide the comparability among areas necessary to the performance of the required cost-benefit analysis since the net economic value estimates measure benefits to the Nation as a whole. Also, in order to make costs and benefits comparable, the social cost analysis is keyed to the leasable resource estimates used in the net economic value analysis (see Table 2). Leasable resources are calculated on a "risked" basis--i.e., incorporating an estimate of the probability of occurrence of potential effects as well as their magnitude. The EIS, on the other hand, will be based on "conditional" resource estimates, which are usually larger because they are not modified by a risk factor. Nonetheless, this social cost analysis errs on the side of overstating costs in a number of ways.

A vitally important reason that the estimates of social costs are likely overstated is that development of the United States' OCS oil and gas resources is conducted in an increasingly safe and environmentally sound manner. The program has an excellent record of few personnel and mechanical failures which have resulted in environmental damage or adverse coastal zone impacts (see Appendix Q). While the calculations are based on historical data, advances in technology have lowered and can be expected to continue to lower the chance of such damage and impacts. However, if there were an increase in activities in areas with harsh operating conditions, that trend might be affected adversely. The substantial OCS oil and gas environmental studies program of the Department of the Interior (DOI) is continuing to shed light on where and how damages may occur and how they can be prevented. The regulatory and operating procedures of the DOI have mitigated and will continue to mitigate many of the potential damages.

Furthermore, the OCS Lands Act provides a means to compensate those who are adversely affected in the event that OCS oil spill-related damage or commercial fishing gear losses occur. While not taken into account in the computation of social costs, those compensation payments have been used to compute the distribution of costs discussed in Part II.C.

A full description of all the potential costs estimated for this analysis is presented in Appendix G. The introduction and summary to Appendix G also provides a more detailed explanation of the analytical approach, the meaning of social costs, the method of calculation, the data sources used, and the reliability of estimates.

Social Costs

Social costs include the costs of responding to and cleaning up oil spills, commercial fishing loses, recreation, air quality, and wetland losses, infrastructure costs, research and legal costs, and other market and non-market

valued environmental and socioeconomic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production, and transportation.

In this analysis, social cost estimates are related to potential large oil spills (1,000 barrels or more), small spills (under 1,000 barrels), spill control and cleanup costs, commercial fishing losses, recreation losses, potential ecological damages, real property losses, legal expenses, subsistence losses, the value of oil spilled, research expenses, and other costs. Estimates were also made for the following potential non-oil spill costs: potential air quality losses; onshore wetlands losses; losses resulting from physical conflicts between commercial fishing and OCS oil and gas operations; and infrastructure costs.

Since social costs are costs to the Nation as a whole, they are measured net of the social costs avoided because OCS oil reduces the quantity of oil imported and hence reduces spills of imported oil. Thus, Appendix G first calculates gross social costs and then subtracts from that figure the costs avoided because oil imports are reduced in order to calculate the net social costs displayed in Table 7.

Of the potential OCS oil and gas damages that could occur, the analysis was restricted to those for which cost data (in dollars) exist and, in the professional judgment of the staff of the MMS could be adapted to the analysis. Additional information about these potential damages as well as information about other potential quantifiable damages and unquantifiable damages which were not included in this analysis will be described in the EIS and elsewhere in the SID. These descriptions, along with this social cost analysis, will allow consideration of variations in potential environmental damage and adverse coastal zone impacts from planning area to planning area in selecting the timing and location of leasing.

Comparison of the New Analysis and the 1982 Analysis

The analysis of social costs updates, refines, and extends a similar analysis undertaken in formulating the 1982 5-Year Proposed OCS Leasing Program. The current analysis reflects three major differences: (1) updated and considerably lower estimates of unleased oil and natural gas resources; (2) substantially lower tanker oil spillage rates; and (3) refinements in the analysis. The net effect of these changes is to increase the new estimated potential social costs of developing oil and gas resources in the Central and Western Gulf of Mexico and to decrease the estimated costs of developing hydrocarbon resources in other areas.

Appendix G demonstrates a number of fundamental differences between the total and per-barrel social costs estimated in connection with the 1982 proposed 5-year leasing program and the social costs estimated for consideration in the formulation of the new program. Estimated oil spill and non-spill costs per unit of production in general are considerably less in this analysis than those estimated in 1982. Mitigating measures to avoid wetland and air quality losses, lower oil spillage rates because of improved tanker and pipeline safety records, as well

as lower resource estimates and the use of refined economic concepts explain the lower costs in this analysis as compared to the 1982 results. The major differences between this analysis and the 1982 analysis are explained in section H of Appendix G.

The Social Cost Analysis

Estimates of the potential costs in each category of damage were based on data and judgments derived from the results of a literature search, the analysis of relative environmental sensitivity and relative marine productivity (see Part II.B.3 and Appendix I), knowledge of the value of other uses of the sea, the estimated amount of oil and gas production, the chance of spills reaching shore, the likelihood of resulting damage in each area, information received in response to requests for comments (summarized in Appendix B), and a number of other factors.

The potential social cost estimates are summarized in Table 7. Table 7 shows that the estimates associated with the development of the leasable resources in each planning area range from a total estimated social cost of $32.5 million for the Central Gulf of Mexico to a total social cost of less than $0.5 million for several Alaskan OCS areas, the Straits of Florida, and Washington-Oregon.

Estimated potential social costs vary considerably depending on the planning area. For instance, recreation losses caused by oil spills are estimated to be relatively low in the Alaskan areas but higher elsewhere. Based on an analysis of commercial fishing landings statistics published by the National Marine Fisheries Service and the State of Alaska, commercial fishing losses per barrel of oil spilled are estimated to be high in the North Atlantic and Central Gulf of Mexico and moderate to low for other areas. Also, it is estimated that per-barrel subsistence losses may be significant in some areas of Alaska, but they are projected to be negligible outside Alaska. The estimated unit cost of oil spill control and cleanup is considerably higher for Alaskan areas vs. the "lower 48" (see Appendix G).

Losses per billion barrels of oil equivalent (BBOE) due to air pollution were judged to be negligible in all the Alaskan areas except Cook Inlet, where they were estimated to be low. Air pollution losses in areas of the contiguous 48 States are negligible except for the Southern California area and the Central Gulf of Mexico area, where they are estimated to be low, due in large part to the concentrated coastal population and the topographical features and climate of these areas. (see Appendix G).

Generally speaking, there is a direct relationship between a planning area's total potential social cost and the total hydrocarbon resources estimated to be produced in the area. However, the oil-gas resource composition, the probability of a spill reaching shore, the value of each area's marine resources, and socioeconomic characteristics influence estimated social costs. The relative marine productivity/environmental sensitivity analysis is also an input to the estimation of potential social costs as well as a separate consideration in itself.

Table 7

Range of Estimated Potential Net Discounted Total Social Costs Associated with Total Production of the Leasable Resources Estimated to be in Each Planning Area (In Millions of $ 1987) /1

Central Gulf of Mexico	$40.46 - 40.52
Western Gulf of Mexico	28.86 - 29.44
Southern California	16.97 - 20.10
Navarin Basin	6.58 - 26.97
Northern California	4.80 - 6.36
Central California	5.10 - 6.24
Eastern Gulf of Mexico	4.89 - 6.48
South Atlantic	2.78 - 4.61
St. George basin	0.00 - 2.90
Beaufort Sea	* - 6.24
Mid-Atlantic	0.89 - 1.51
North Atlantic	0.78 - 0.98
Washington-Oregon	* - 0.54
Straits of Florida	* - *
Chukchi Sea	* - 5.28
North Aleutian basin	* - *
Gulf of Alaska	* - *
Norton Basin	* - *
Kodiak	* - *
Hope Basin	* - *
Shumagin	* - *
Cook Inlet	* - *

/1 Net Present Value, calculated with a discount rate of 8 percent (see Appendix G). The low numbers in the range correspond to resource estimates based on a $19 per barrel starting oil price and the high numbers correspond to a $29 per barrel starting oil price. The planning areas are ordered for total social cost values @$24 per barrel.

* Estimated to be less than $0.5 million.

The net effect of the factors influencing potential social costs is indicated in Table 8 by the social costs per unit of production--here measured as the social costs per billion barrels of oil equivalent (BBOE). The rankings of the areas in terms of costs per BBOE differ from their total cost rankings. In several cases, areas with relatively low estimated recoverable resources have relatively high social costs per BBOE reflecting a combination of factors (environmental sensitivity and productivity, high valued commercial fisheries, recreation losses and cleanup costs, particularly for areas where there is a high chance that any spills which occur will come ashore).

Potential wetland losses from onshore development related to OCS production, although considerably lower than similar estimates made in 1982, are estimated to be highest for the Central /1 and Western Gulf of Mexico and Southern California areas. The key determinants of these estimates are the additional activity estimated to take place in each area, the extent to which existing facilities can accommodate the additional activity, and the effectiveness of governmental permitting requirements in mitigating these potential losses (see Appendix Q).

While social costs measure the estimated potential cost of producing the area's unleased leasable resources to the Nation as a whole, the estimate does not indicate the distribution of costs among the population. The distribution of such costs is treated in Part II.C, in the discussion of the equitable sharing of developmental benefits and environmental risks.

Because of the uncertainty and difficulties associated with estimating several categories of cost, a sensitivity analysis was carried out to determine the magnitude of an area's social cost that would be estimated if specific unit costs are presumed to be even higher than the overstated costs used to develop the estimates of social costs presented in Table 7. The results of the sensitivity analysis in Appendix G indicate that while the costs in each planning area are greater than the results presented in Table 7, the ranking of OCS areas by their net social value (see Part II.D of this SID) does not change. This is because: (1) only a subset of all costs (i.e., the largest and most uncertain costs) is assumed to increase; and (2) when individual oil spill costs increase, the social cost savings from backing out imported oil also increase, thereby moderating the net increase in social costs.

Nonetheless, in assessing the results of the analysis, it is important to keep in mind the high degree of uncertainty associated with the estimates. Given the uncertainty of the data on which the analysis was based, and the necessity of heavy reliance on judgment, the social cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would make distinctions between differences from area to area only if they are substantially more than an order of magnitude in size (that is, if one estimate is substantially more than 10 times the other).

/1 The loss of coastal wetlands has been most pronounced in the Central Gulf of Mexico. Current information on the processes causing wetland loss implicates large-scale geologic and oceanographic processes along the Louisiana coast. In comparison to these other forces, OCS-related activities do not appear to have been a significant contributor to the loss of coastal wetlands in this area. (See Appendix G).

Table 8

Estimated Potential Social Costs Per Billion Barrels of Oil Equivalent (BBOE) Associated With Total Production of Leasable Resources Estimated to be in Each Planning Area (In Millions of $ 1987) /1

Area	Net Costs Per BBOE
Straits of Florida	$53
Navarin Basin	34
Cook Inlet	28
Norton Basin	22
North Atlantic	22
Beaufort Sea	21
St. George Basin	18
North Aleutian Basin	18
Southern California	16
Central California	15
Northern California	15
Kodiak	15
Gulf of Alaska	14
Eastern Gulf of Mexico	14
Chukchi Sea	13
Washington-Oregon	10
Shumagin	9
Central Gulf of Mexico	9
Mid-Atlantic	8
Hope Basin	8
Western Gulf of Mexico	6
South Atlantic	6

/1 Net Present Value, calculated with a discount rate of 8 percent assuming a starting oil price of $29 per barrel. The $29 per barrel estimates are presented because nine planning areas have no leaseable resources at $19 per barrel. The variation of the BBOE social costs for most planning areas is quite constant across the $19 per barrel to $29 per barrel resource estimates. The BBOE net social cost estimates for the Cook Inlet, Hope Basin, Kodiak, and Shumagin planning areas were calculated using estimates of developable resources with a $29 per barrel oil price (see Appendix G).

The Straits of Florida has the highest net social costs per BBOE across all planning areas even though its total social costs are among the lowest (less than $0.5 million). The very high costs per BBOE result from dividing the estimated total net social costs for the Straits of Florida by the estimated leasable resources and then expressing the costs on a per BBOE basis (see Appendix G). The estimated social costs for the Straits of Florida are nearly all fixed costs (wetland loss due to pipeline installation), which would not increase proportionately if the resource estimate increased. Thus, the BBOE cost for the Straits of Florida would be lower if the resource estimate were higher. [Footnote continued on the next page.]

(Footnote /1 continued).

The problem of high fixed costs distorting the BBOE estimates of net costs does not fully explain the high BBOE costs for the Navarin Basin. The high net social costs per BBOE for the Navarin Basin are caused by a combination of factors the most important of which are the transportation scenario for the Navarin Basin and the relatively high oil to gas ratio for the Navarin Basin.

Oil produced from the Navarin Basin will be transported by pipelines to either onshore or offshore tanker loading facilities. Ice breaking tankers will be used to transport Navarin Basin oil to a port on the south side of the Alaska peninsula where it will be off-loaded and loaded onto tankers for shipment to market. Thus, Navarin Basin oil has three transportation legs with their attendant risks of oil spills while all other planning areas outside of the Bering Sea have only one or two transportation legs. This extra tanker transportation segment for the Navarin Basin increases its estimated oil spillage per billion barrels by more than 50 percent over planning areas that use both pipelines and tankers, i.e., all Atlantic planning areas and all other Alaskan planning areas. By comparison to planning areas that use pipeline or tankers, but not both, Central and Western Gulf of Mexico and Southern California, the additional oil spillage for the Navarin Basin is even larger. The estimated amount of oil spilled per billion barrels for the Navarin Basin is over 213 percent larger than the estimated amount of oil spilled per billion barrels for the Central Gulf of Mexico.

The ratio of oil to gas in a planning area's resources can also affect the net social costs per BBOE. The Navarin Basin is estimated to have about 82 percent oil in its BBOE while other planning areas have lower percentages oil in their BBOE. For example, the Central Gulf of Mexico has approximately 40 percent oil in its BBOE while the Western Gulf of Mexico has less than 30 percent oil in its BBOE. Production of gas increases the BBOE for a planning area but does not increase the estimated amount of oil spilled, and most of the social costs are related to spilled oil. Thus, planning areas with a high percentage of oil in their BBOE, like the Navarin Basin, tend to have higher per-BBOE social costs.

II.B.3. Relative Marine Productivity and Environmental Sensitivity

Section 18(a)(2)(G) of the OCS Lands Act, as amended, requires that the Secretary of the Interior consider the relative marine productivity and environmental sensitivity of the various oil and gas bearing physiographic regions of the OCS in determining the timing and location of oil and gas activities. Analyses of relative marine productivity and environmental sensitivity were conducted to aid in the development of the 1982 OCS leasing schedule (Part II.B and Appendix 10 of the SID for the 1982 program). Those analyses demonstrated the complexity of collecting, analyzing, and interpreting scientific information to satisfy the requirements of section 18(a)(2)(G). In spite of the difficulties described in the 1982 analyses, the approaches to those analyses were upheld as reasonable by the U.S. Court of Appeals for the District of Columbia on July 5, 1983.

In preparation for current analyses, analytical approaches were discussed with the OCS Advisory Board Policy Committee (October 1984) and Scientific Committee (November 1984). The present analysis incorporates some of the advice and guidance received. Some of the suggestions from these advisory groups were more appropriate to environmental analyses which will follow the present analyses. These suggestions will be considered during the preparation of the environmental impact statement (EIS) for the proposed program and in subsequent sale-specific EIS's. Almost all parties who provided advice agreed that both the productivity and sensitivity analyses required by section 18(a)(2)(G) are complex and difficult. In addition to this advice, the Department has received or developed more information on the habitats and biota of the OCS than was available in 1982. The principal mechanism for the Department to develop such information is the OCS Environmental Studies Program administered by the Minerals Management Service.

Appendix I contains a more detailed explanation of the relative marine productivity and environmental sensitivity analyses summarized here. The information developed in the present analyses will be considered in and of itself as well as an input to the social costs analysis in Part II.B.2 and Appendix G of this SID. The assumptions used to determine the environmental sensitivity of a habitat or resource differ from those used in the analysis of social costs in the following ways:

1. The probability of the occurrence of an oil spill is an integral part of the calculation of social costs. This probability is a function of the estimate of oil and gas resources in the planning areas. The sensitivity analysis is based upon the assumption that an oil spill has occurred and that the spilled oil has contacted habitats or biota of the planning area. The sensitivity analysis does not rely upon resource estimates or consider the probability of the occurrence of an oil spill.

2. The calculation of social costs includes potential costs from air pollutant emissions and the loss of coastal wetlands. These impacts are not included in the sensitivity analysis.

3. The analysis of social costs includes losses of commercial and/or subsistence fish resources. The present analysis includes evaluations of the sensitivity of juvenile and adult fish and shellfish to crude oil. The social use of these resources is not considered in the sensitivity analysis.

Relative Marine Productivity

The term "productivity" has a distinct meaning to marine biologists. It means the "primary productivity" of marine plants. Primary productivity is the amount of plant tissue produced through photosynthetic fixation of carbon during a standard period of time. Both phytoplankton, microscopic marine plants, and fixed or rooted plants contribute to the primary productivity of most OCS planning areas. However, phytoplankton are the most important primary producers because of their large numbers and their wide distribution. Rooted or fixed plants are generally confined to the shallow portions of the planning areas. Phytoplankton can occupy all surface waters of a planning area and can fix carbon as long as sufficient light and nutrients are available. Riley (1970) estimated the normal range of marine primary productivity to be between 50 and 150 grams of carbon per square meter of ocean surface per year. Productivity in inshore areas and areas of upwelling can be as much as ten times greater than oceanic productivity.

The primary productivity of phytoplankton was used to rank the various planning areas in the 1982 analysis of relative marine productivity. Measurements of phytoplankton productivity have been made in almost all of the planning areas. The methods for measuring phytoplankton productivity are relatively standard. Most of the data used in the present analysis, except that provided by Smith and Kalber (1974), is based on ^{14}C assimilation measurements of phytoplankton productivity. Results of phytoplankton productivity studies are expressed in terms of the amount of carbon fixed during photosynthesis per unit area in a specified time. The figures used in the present analysis are expressed as grams of carbon fixed per square meter per year ($gC/m^2/yr$). By using a period of one year for reporting primary productivity, periods of extremely high or low productivity are incorporated in their appropriate importance in terms of their contribution to the annual productivity. This is especially important in areas where productivity is highly seasonal.

Phytoplankton productivity can vary more significantly within a planning area than between planning areas. For example, O'Reilley and Busch (1984) reported that productivity in the shallow areas of Georges Bank (North Atlantic) averaged 470 $gC/m^2/yr$ while in deeper waters landward of the shelf break, productivity averaged 370 $gC/m^2/yr$. Productivity in the deeper waters of the North Atlantic averaged 230 $gC/m^2/yr$. Determining an appropriate range or average productivity rate for the North Atlantic or any other planning area requires careful attention to the temporal and spatial significance of reported observations.

The 1982 analysis of marine productivity relied upon the "Estimation of organic production in the oceans" (Figure 1.1-5) presented by Smith and Kalber (1974). The productivity ranges provided in that undocumented map

were used to rank the OCS planning areas. In the present analysis, the estimates of Smith and Kalber (1974) were compared with more current estimates based upon documented measurements (Table 9.1). In the 1982 analysis, the planning areas were grouped into four productivity classes: highest, next-to-highest, next-to-lowest, and lowest. The North Aleutian Basin and the St. George Basin were the only planning areas in the "highest" class. Based upon the data of Goering and McRoy (1981), the average annual productivity of these planning areas is substantially lower than the values reported by Smith and Kalber (1974). Only three productivity classes (high, moderate, and low) were distinguished in the present analysis (Table 9.2).

Twelve planning areas are included in the "high productivity" class. Further differentiation within this group must await more precise definition of the appropriate ranges or other statistical descriptions. The principal difference between the present analysis and the 1982 analysis is the elimination of the "highest" productivity class from the 1982 analysis and the inclusion of the North Aleutian Basin and the St. George Basin in the "high" productivity class of the present analysis.

In the present analysis, the planning areas designated as having "moderate" productivity are those with reported observations ranging from 50 to 200 $gC/m^2/yr$. Seven planning areas occur in this class. Although some high observations are reported for some of these areas, the overall annual productivity of these areas appears to be in the "moderate" range.

Finally, the three planning areas in the Arctic (Hope Basin, Chukchi Sea, and Beaufort Sea) are the least productive of the OCS planning areas. Information from Carey (1978) and Schell and Horner (1981) confirms the low productivity of these areas.

Additional Measures of Marine Productivity

The phytoplankton productivity data discussed in the present analysis is some of the most consistently expressed data in biological oceanography. Even so, comparisons among observed productivities are tenuous for the reasons described in the preceding discussion. The problems associated with attempting to use other biota to assess marine productivity are illustrated in Table 6 of the 1982 analysis. Even with the additional data collected since 1982, available information is not sufficient to support a rigorous evaluation of the relative abundance of various organisms in the OCS planning areas. In many instances, quantitative information on some biota is unavailable, while for others, the development of "planning-area representative" information is not practical.

However, information on the relative abundance of eight additional categories of biota was compiled, reviewed, and used in the matrix exemplified in Table 9.3 to complete the environmental sensitivity analysis. Available information on standing stocks and distributions was used to determine whether the "abundance" of the biota in a planning area relative to all other planning areas was high, moderate, or low. Making such determinations generally required extrapolations of existing data and simplifying assumptions. Some of these extrapolations and assumptions are described in the following sections.

TABLE 9.1

Marine Phytoplankton Productivity by Planning Area
Expressed as Grams of Carbon Fixed per Square Meter per Year

Planning Area	Range of Values Used in the 1982 Analysis (gC/m²/yr)*	More Recent Observations (gC/m²/yr)	Reference
North Atlantic	200-400	230-470	O'Reilly & Busch (1984)
Mid-Atlantic	200-400	260-370	O'Reilly & Busch (1984)
South Atlantic	50-200	130-360	Haines & Dunstan (1975) Yoder et al. (1983)
Straits of Florida	50-100		
Eastern Gulf of Mexico	50-100	10-110	UMES (1985)
Central Gulf of Mexico	50-100	10-220	El-Sayed & Turner (1977)
Western Gulf of Mexico	50-100	15-70	El-Sayed & Turner (1977)
Southern California	200-400	180-360	Eppley et al. (1979)
Central California	200-400	10-470	Riznyk (1977)
Northern California	200-400	10-470	Riznyk (1977)
Washington/Oregon	------	35-350	Small et al. (1972)
Gulf of Alaska	200-400		
Cook Inlet	200-400		Griffiths et al. (1982)
Kodiak	200-400		
Shumagin	200-400		
North Aleutian Basin	400-7300	120-400	Goering & McRoy (1981)
St. George Basin	400-7300		
Navarin Basin	50-200		
Norton Basin	50-100		
Hope Basin	50		
Chukchi Sea	50	18-28	Carey (1978)
Beaufort Sea	50	10-20	Schell & Horner (1981)

* Range from Smith and Kalber (1974)

TABLE 9.2

Relative Phytoplankton Productivity of the OCS Planning Areas
Expressed as Grams of Carbon Fixed per Square Meter per Year

High Productivity (200 to 500 $gC/m^2/yr$)

North Atlantic
Mid-Atlantic
North Aleutian Basin
St. George Basin
Southern California
Central California
Northern California
Washington and Oregon
Gulf of Alaska
Cook Inlet
Kodiak
Shumagin

Moderate Productivity (50 to 200 $gC/m^2/yr$)

South Atlantic
Straits of Florida
Eastern Gulf of Mexico
Central Gulf of Mexico
Western Gulf of Mexico
Navarin Basin
Norton Basin

Low Productivity (<50 $gC/m^2/yr$)

Hope Basin
Chukchi Sea
Beaufort Sea

Relative Environmental Sensitivity

The concept of environmental sensitivity is even more complex than the concept of marine productivity. The 1982 analysis clearly demonstrated this complexity.

The 1982 analysis of environmental sensitivity was based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to spilled crude oil. Limiting the analysis to spilled crude oil provided the following advantages:

1. Different areas of the OCS could be evaluated against a common factor, in this case, spilled crude oil.
2. Effects from overlapping factors could be avoided.
3. Oil spills, although rare, would cause the largest, most visible, and measurable effects of OCS activities.

The present analysis of environmental sensitivity also concentrates on the effects of spilled oil. However, some other factors were also evaluated in Appendix I-2 of the draft proposed program. These evaluations are not repeated in the proposed program but are available for review. These factors include the following:

1. Operational discharges from OCS activities (drilling muds, cuttings, and formation waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

These factors are not included in the calculations because of the difficulty of measuring their effects on the same basis that the effects of oil spills. In addition, information on the effects of these factors on habitats and biota throughout the entire OCS is not available. The effects of operational discharges, noise, habitat alteration, and air emissions will be considered in other environmental analyses prepared for the 5-Year Program, such as the EIS on the proposed program, and in subsequent sale-specific EIS's. While the cumulative effects of these four factors may be more extensive and long lasting than the effects of a large oil spill, the Department of the Interior and other Federal, State, and local agencies have means available to control some of the adverse effects of these factors.

For the present analysis, environmental sensitivity is defined in terms of the following variables:

1. the severity of damage resulting from the contact of spilled oil with various coastal and marine habitats and biota (this was designated as the persistence of oil in the 1982 analysis), and

2. the time required for the habitat or population to recover from the effects of contact with spilled oil.

The following assumptions are also included in the present environmental sensitivity analysis:

1. Spilled oil has not weathered significantly when it contacts the habitat or population. This assumption is conservative and provides an assessment of the most severe effects of spilled oil by eliminating the mitigating effects of weathering in the analysis. It also eliminates consideration of the distance between sensitive resources and potential oil fields or transportation routes and the mitigating effects of weathering on spilled oil moving from the site of production or transportation to the sensitive resource.

2. All of the biological populations in a planning area are contacted by spilled oil. Migratory species, which may inhabit the planning area for only a short period, are assumed to be present and contacted by spilled oil. Resources with seasonal sensitivities are assumed to be in their most sensitive stage when they are contacted by oil.

Performing an accurate analysis of environmental sensitivity requires a substantial amount of information on the spatial and temporal distribution of resources and the variations in their sensitivities to spilled oil. This is especially true where seasonal phenomena such as changes in productivity or the presence of migratory species would significantly increase or decrease the overall sensitivity of a planning area. If sufficient data were avialable, the overall environmental sensitivity of a planning area would be the sum of the sensitivities of its components integrated over time. This concept was reviewed during the preparation of the present analysis. It was abandoned because the minimum necessary information to conduct such an analysis is not available. Some information on some resources in some planning areas is avaiable, but the data are neither consistent nor available for all planning areas. As a result, the present analysis contains the simplifying assumptions described above. If adequate information were available, it would be possible to develop both expected and worst-case sensitivities. The reliance of the present analysis on conservative assumptions is, nonetheless, appropriate for the purpose of comparing the relative environmental sensitivities of the OCS planning areas.

Relative Marine Productivity/Environmental Sensitivity

In the present analysis, the distributions and environmental sensitivities of the three ecological components within and/or on the adjacent coast of each OCS planning area are evaluated. These three components are coastal habitats, marine habitats, and biota. Table 9.3 is an example of the calculations performed for each of these components. The calculations for each planning area are included in Appendix I-1.

The relative marine productivity and environmental sensitivity of the OCS planning areas are shown in Table 9.4. Alaskan OCS planning areas occupy the extremes of this table. The Navarin Basin has the lowest score because it has no coastal habitats. The planning areas with the highest scores are Hope Basin, North Aleutian Basin, St. George Basin, and Norton Basin. Since much of the information used in the calculation of relative marine productivity and environmental sensitivity is qualitative, each assigned value in the calculation has some degree of uncertainty. Thus, the scores provided in Table 9.4 should be viewed as estimates surrounded by some undefined variance. Scores with small differences between them should be viewed as relatively equal.

TABLE 9.3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hypothetical

Overall Total Score: 290

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	200	33	High	225	74.25
Sandy Beaches	300	50	Low	45	22.50
Rocky Beaches	100	17	Moderate	135	22.95
TOTAL	600				119.70

Marine Habitats	Acres				
Submerged Vegetation	1,200,000	5.3	Moderate	135	7.16
Submarine Canyons	None	0.0	Low	45	0.00
Coral Reefs	5,000	0.02	High	225	0.05
Hard Bottoms	600,000	2.6	Low	45	1.17
Shelf Break Zone	850,000	3.7	Low	45	1.67
Mud/Sand Bottom	20,000,000	88.2	Low	45	39.69
TOTAL	22,655,000				49.74

Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	Moderate	3	Moderate	3	15
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	Moderate	3	High	5	15
TOTAL					120

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE 9.4

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas

Planning Area	Overall Total Score
Hope Basin	349
North Aleutian Basin	327
St. George Basin	281
Norton Basin	280
Cook Inlet	272
Shumagin	265
Kodiak	264
Beaufort Sea	261
Washington-Oregon	256
Central Gulf of Mexico	254
Northern California	239
Gulf of Alaska	235
South Atlantic	230
Straits of Florida	228
Central California	227
Southern California	213
North Atlantic	209
Eastern Gulf of Mexico	208
Chukchi Sea	204
Mid-Atlantic	198
Western Gulf of Mexico	130
Navarin Basin	131

READEX

The results of this analysis are consistent with available information on the relative sensitivity of the resources to spilled oil. The results are also consistent with the current concepts of relative sensitivity of coastal and marine habitats (COPRDM, 1981; NRC, 1985). This is most clearly shown for the Navarin Basin where coastal habitats are negligible. In addition, the presence of high populations of sensitive biota (coastal and marine birds, marine mammals, whales, juvenile fish and shellfish) are the major factors supporting the high overall scores of the Alaskan planning areas. The ecological component which has the least effect on the overall scores is marine habitats. This results from the assumption that spilled oil cannot be transported in significant amounts from the surface of the ocean to most benthic commuities. The most sensitive marine habitats that could be affected are submerged vegetation and coral reefs. These habitats do not occupy a significant portion of any planning area.

Several commenters criticized the analysis of relative marine productivity and environmental sensitivity because of dissatisfaction with the results. In particular, the scores for marine habitats were criticized because the sensitivity of marine habitats in many diverse planning areas were scored the same due to lack of data. However, this lack of data on areal extent of marine habitats is not considered critical as most marine habitats are judged to have low sensitivity to spilled oil (Appendix I-2) and therefore, are scored equally.

The method used to generate Overall Total Scores was modified to ascertain the significance of having equal scores for marine habitats in diverse planning areas. The ranking of planning areas as to their relative marine productivity and environmental sensitivity was determined both as a composite of the individual scores for coastal habitats, marine habitats, and biota (Table 9.4) and for coastal habitats and biota without marine habitats (Table 9.5). The final order of planning areas is practically identical whether marine habitats are considered or not. As stated previously, scores with small differences between them should be viewed as relatively equal. Thus, the model is not sensitive to the lack of data on areal extent of low sensitivity marine habitats.

The results of this analysis should not be construed as indicating the level of impacts expected as a result of OCS development. In this analysis, sensitivity is determined from the likely response of the resource to the environmental perturbation without consideration of risk, likelihood of adverse impact, or vulnerability. Thus, the sensitivity ratings represent a conservative analysis. Additional factors would need to be considered to determine the expected level of impacts in a planning area from OCS oil and gas operations. These factors include the projected amount of hydrocarbon resources, their probable location within the planning area, the number and trajectory of hypothetical oil spills, and the location of possible spill sites, among others.

A high overall score or the presence of many sensitive resources in a planning area does not necessarily imply a high level of adverse effects from OCS development. Even those areas ranked with relatively low scores possess sensitive resources which will require consideration of specific environmental impacts at the sale stage and evaluation to determine the need for special protective measures.

TABLE 9.5

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas Calculated as the Sum of the Scores for Coastal Habitats and Biota

Planning Area	Score
Hope Basin	293
North Aleutian Basin	281
Cook Inlet	226
St. George Basin	222
Norton Basin	217
Kodiak	217
Shumagin	215
Beaufort Sea	211
Washington-Oregon	211
Central Gulf of Mexico	209
Northern California	194
Gulf of Alaska	186
South Atlantic	184
Straits of Florida	183
Central California	182
Southern California	168
North Atlantic	162
Eastern Gulf of Mexico	156
Chukchi Sea	155
Mid-Atlantic	153
Western Gulf of Mexico	135
Navarin Basin	86

The principal commenters on Appendix I of the Draft Proposed Program were the Natural Resources Defense Council (NRDC), the U.S. Environmental Protection Agency (EPA), and the National Oceanic and Atmospheric Administration (NOAA).

The NRDC expressed its greatest concerns about the marine productivity analysis and the rationale for lowering the productivity class of the North Aleutian Basin and the St. George Basin. Additional scientific information has been presented in Appendix I to demonstrate the basis for this action. The data presented clearly support the lower annual productivity. The NRDC comments will not lead to major changes in the conclusions of the analysis.

The EPA also expressed concern about the North Aleutian Basin and the St. George Basin productivity figures. The additional information presented in Appendix I should make clearer the MMS's rationale for the lowering of the productivity class of these planning areas. The EPA also presented a lengthy discussion of the complexities of the sensitivity analysis and alternative approaches. These approaches have been reviewed. The most easily implementable of these suggestions would be counter to the advice provided by the Scientific Committee of the OCS Advisory Board. The EPA suggestions would also make the analysis extremely complex and difficult to follow. Many of the suggestions, such as discussions of ecosystem interactions, are more appropriate to sale-specific EIS's.

The NOAA provided some clarification and qualification of productivity and sensitivity data used in the social costs analysis (Appendix G). As appropriate, this information in incorporated into Appendix I.

II.C. Equitable Sharing of Developmental Benefits and Environmental Risks

Section 18(a)(2)(B) requires that the Secretary base the timing and location of OCS exploration, development, and production on a consideration of, among other things, an

> ". . . equitable sharing of developmental benefits and environmental risks among the various regions."

Compliance with this requirement involves four key elements which will be addressed in this section: 1) the identification and presentation of developmental benefits and environmental risks; 2) the description of their actual sharing among the various regions; 3) the discussion of the concept of equitable sharing; and 4) the discussion of how the "consideration of . . . an equitable sharing. . ." is to be reflected in the scheduling of OCS lease sales.

In California v. Watt (II) (at 594), the court upheld the sufficiency of the analysis under section 18(a)(2)(B) which was presented in the SID for the 1982 leasing program. The analysis presented here uses the same approach, but is somewhat expanded.

Distribution of Benefits and Costs to Regions

The developmental benefits which will be analyzed in this section are the economic benefits which comprise the net economic value of production as described in Part II.B.1 and Appendix F. The environmental risks which will be discussed in this section are the social costs which are analyzed in Part II.B.2 and Appendix G.

Estimates of both economic benefits and social costs have been calculated on a planning area basis. These estimates are shown in Tables 3 and 7, respectively. While we can attribute certain benefits and costs to activity in a particular planning area of the OCS, how these benefits and costs are shared by the population onshore is not as obvious.

The court upheld the Secretary's consideration of the equitable sharing of the developmental benefits and environmental risks among the people of seven regions comprised of one or more coastal States in addition to the sharing among OCS planning areas. For this third 5-year program, basically the same seven regional units are also used, as follows:

Region I - Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia

Region II - North Carolina, South Carolina, Georgia

Region III - Florida

Region IV - Texas, Louisiana, Mississippi, Alabama

Region V - California

Region VI - Washington, Oregon

Region VII - Alaska

The alternative of limiting regions to individual coastal States in all cases would make the analysis less informative. Because there is more uncertainty in estimating the environmental risks borne by individual States as opposed to those borne by the regional grouping in Regions I, II, IV, and VI, the regional approach has been retained in those cases. Where that limitation does not apply, however, single States have been treated as regions--as in the 1982 analysis (e.g., Regions III, V, and VII). It should be noted that Regions V and VI share some of the environmental risks arising from production offshore Alaska (see Appendix G). It should also be noted that Pennsylvania has been added to Region I. While Pennsylvania has no coastline directly adjacent to the OCS, Pennsylvania is defined as an affected State in 43 USC 1331 and 30 CFR 256.14.

Equitable Sharing and the Scheduling of OCS Lease Sales

Further discussion of equitable sharing occurred in the court's review of whether the 1982 leasing program was based on the factors listed in section 18(a)(2). It should be noted that the court did not define a standard of equitable sharing of developmental benefits and environmental risks which the Secretary was to achieve. Rather, the court sanctioned the Secretary's choice of a program which scheduled sales so as to be conducive to an equitable sharing of environmental risks among OCS regions.

In its opinion, the court held that in some circumstances it was appropriate to determine the location of sales in various planning areas on a basis other than relative net social value. Net social value is the measure of the overall value of oil and gas production to the Nation calculated by subtracting the social costs of such production (analyzed in Part II.B.2 and Appendix G) from its net economic value (analyzed in Part II.B.1 and Appendix F).

In particular, the court found that it was appropriate to schedule sales so as to expedite exploration in frontier areas (California v. Watt (II) at 599). Thus, leasing need not be scheduled in a manner that strictly reflects the projections of high value and potential for discovery in higher net social value areas in contrast to frontier areas. One basis for such an approach is the recognition that net social value estimates are only approximate indicators of what will result from OCS leasing. As was discussed in Part I, many effects are not quantifiable and thus cannot be included in the net social value calculation. In addition, actual hydrocarbon deposits may well prove to be distributed quite differently than as predicted by today's best estimates. Indeed, the court also recognized in a different but still relevant context that ". . . the Secretary realized that the cost-benefit analysis [i.e., the calculation of the net social value of planning areas and alternative schedules] should be used only for generalized conclusions. He did not think that the analysis would provide an adequate basis for making distinctions between planning areas" (California v. Watt (II) at 605).

In light of the court's opinion, the factors which need to be considered in making a determination about the equitable sharing of developmental benefits and environmental risks include numerous significant factors not under the control of the MMS to wit: the natural distribution of oil and gas resources among the areas of the OCS; the history of development of technology for oil and gas exploration, development, and production; the history of industry exploration and production strategies in State waters as well as the OCS; and the congressional and injunctive constraints which have been imposed on OCS leasing. The MMS's estimates of the natural distribution of economically recoverable oil and gas can be found in Appendix E. A brief summary of the history of leasing offshore can be found in Appendix F.

The fact that the court sanctioned the scheduling of more sales in frontier areas than would result from relative net social value alone has the further implication that the equitable sharing sought by the OCSLA, as amended, has to be interpreted in light of the overall purposes of the OCS Lands Act Amendments (OCSLAA), the first of which is "to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade" (OCSLAA section 102(1)). In this context, the court explicitly upheld "...the Secretary's interpretation of the congressional intent to expedite offshore lease sales, particularly in frontier areas" (California v. Watt (II) at 599), emphasis in the original). It is also clear that the equitable sharing of developmental benefits and environmental risks is one among a number of factors whose consideration is mandated by section 18 of the OCS Lands Act.

Thus, the court upheld the grouping of OCS planning areas by their relative net social value as the general basis for scheduling OCS lease sales. The court also provided, however, for the modification of the net social value basis of scheduling sales with respect to frontier areas so that the regional contribution to the achievement of the overall purposes of the OCSLAA could be made more equitable. The full discussion of the scheduling of sales in Part III of this SID reflects the court's interpretation cited just above.

It was, however, in this context that the Draft Proposed Program received several comments from State and local governments, and public interest groups. Some of the commenters believed that equitable sharing, as they interpreted it, had been eroded and that their particular region or jurisdiction is facing unwarranted burden or environmental risk given the proposed leasing schedule, or because limitations on leasing in other areas creates pressure for greater leasing in their area. In particular, the letters from the California Legislature and from several California localities commented that leasing is objectionable, or that the leasing schedule off California is too close and too ambitious and that costs and risks of OCS activities contemplated in the leasing schedule off California did not reflect adequate concern for equitable sharing. This view was shared by Greenpeace, among others. In contrast, the letters from Texas and Louisiana, while supportive of leasing, noted that prohibitions or moratoria in other regions (California and North Atlantic) mean that there will be more OCS activity off their shores than would otherwise be the case, and that the objective of equitable sharing therefore will not be met.

In evaluating these comments, it should be kept in mind that equitable sharing should be viewed from a national perspective, taking into account the benefits that would occur as well as the risks to individual areas. Further, in balancing objectives the program requires as one consideration focusing on acreage with the highest economic value and industry interest among the planning areas. But this is not without full regard for environmental risks and the need to explore frontier areas.

Developmental Benefits and their Distribution

Developmental benefits are largely captured for subsequent distribution in the form of Federal revenues and to a lesser extent in the form of corporate profits. Within each region, some individuals and firms whose labor, land, materials, equipment, or other factors of production are used in OCS development regard the purchase of those resources as a benefit. In this respect, OCS production can

result in development of the kind that States and localities often seek under a variety of local, State, and Federal development programs. From the viewpoint of the Nation, however, the costs of these inputs are subtracted from production revenues in estimating net economic value.

In the context of equitable sharing of benefits among regions, it is worth noting that the States and localities can use tax policies and user fees to capture some of these developmental benefits to pay for the additional public services which may be required by any additional population attributable to OCS development. In fact, it was in this context, with particular regard to perceived infrastructure costs burdening local governments as a result of OCS activities off their jurisdictions that numerous comments were received from local governments and public interest groups and the issues was discussed at the April 1985 meeting of the OCS Policy Committee. This issue is treated in Appendix G and in Part II of the SID, where infrastructure costs are included in social costs. However, while these costs may be real, they do not come without benefits. Indeed, the demands for additional public services as a result of OCS activity comes from increased economic activity and employment that increase the output and income of the locality and are subject to the taxing decisions of the State and the affected localities. While it is recognized that the incidence of costs and benefits may not be perfectly matched, the same may be said of the impact of other major economic or institutional changes, such as the opening of a new automobile plant. The net effect, regionally and nationally, is that economic benefits usually exceed social costs. In Alaska, however, benefits may be lower than in other regions because fewer OCS workers may take up residence in local communities.

The sharing of benefits among the populations of coastal States varies depending upon the form of the benefit. Most developmental benefits are captured for subsequent distribution in the form of Federal revenues from lessees' cash bonus payments, rentals, royalties, income taxes, and other sources. There are a variety of ways to view how the benefits derived from increased Federal revenues would be shared. From one perspective, they would be distributed in about the same way Federal tax payments are collected because without OCS revenues the Federal Government would have to collect equivalent receipts through more taxes to sustain a given level of Federal expenditures. From another perspective, the distribution would be proportional to population because Federal programs benefit the public in general. A third perspective would distribute the benefits in proportion to Federal funds provided to State and local governments. All three ways of sharing benefits could be considered to be equitable because the resources of the OCS are managed by the Secretary on behalf of the public as a whole.

Benefits that arise in the form of corporate profits are distributed to people directly or indirectly in the form of stock dividends or the value of company stock. This distribution tends to be quite wide nationally speaking--it is certainly not likely to be concentrated in coastal areas. Thus, the distribution of company benefits is not unlike the distribution of Federal benefits. On the other hand, many of the perceived benefits from the purchase of factors of production used in OCS development tend to fall within the coastal areas providing the labor and materials used offshore. However, neither of these forms of benefit is likely to be large in comparison to the increases in Federal revenues. For these reasons, consideration of an equitable sharing of developmental benefits in this section is based primarily on the distribution to the various regions of benefits that are captured in the form of Federal revenues.

Table 10. Three Approaches to the Estimated Regional Distribution of Approximately $40 to $92 Billion Variation of Net Economic Value (N.E.V.) Resulting from Production of all Estimated Leasable Resources Unleased as of January 1987/1 (Dollar amounts in billions)

Regions/2	Region's Share of Total Federal Tax Payments/3	Resulting Share of N.E.V.	Regions's Share of Total U.S. Population/4	Resulting Share of N.E.V.	Region's Share of Total Federal Grants/5	Resulting Share of N.E.V.
I	28.0%	$11.1-25.8	25.4%	$10.1-23.4	29.0%	$11.5-26.7
II	5.0	2.0-4.6	6.4	2.5-5.9	5.5	2.2-5.1
III	4.4	1.8-4.1	4.6	1.8-4.2	3.0	1.2-2.8
IV	11.1	4.4-10.2	11.4	4.5-10.5	8.7	3.4-8.0
V	11.8	4.7-10.9	10.7	4.3-9.9	9.9	3.9-9.1
VI	3.0	1.2-2.8	3.0	1.2-2.8	2.9	1.2-2.7
VII	0.3	0.1-0.3	0.2	0.1-0.2	0.6	0.2-0.6

/1 Net economic value was calculated on a planning area basis (see Part II.B and Appendix F). Net economic value was allocated to the adjacent coastal regions in proportion to each region's share of the national total in three specific categories: the region's share of total Federal tax payments; the region's share of population; and in proportion to total Federal intergovernmental grants. The estimated regional share of total net economic value for this table was calculated by multiplying the total net economic value for all planning areas by each region's proportional share (expressed as a percentage) of each of the three variables in the table. The variation of total net economic value equals about $40 to $92 billion. Thus, Region I's share of the total N.E.V., if the distribution were based on its share of total Federal tax payments, would be 28 percent, or $11.1 to $25.8 billion. Regional percentages total less than 100 because only coastal States are included in the calculation.

/2 Regions are--I. Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia; II. North Carolina, South Carolina, Georgia; III. Florida; IV. Texas, Louisiana, Mississippi, Alabama; V. California; VI. Washington, Oregon; and VII. Alaska.

/3 Source: Tax Foundation; Tax Features; April, 1984.

/4 Source: U.S. Department of commerce; Bureau of the Census; Estimates of the Population of the United States to August, 1983; Series P-25; September 1983.

/5 Source: U.S. Department of Commerce; Bureau of the Census; Federal Expenditures By State for Fiscal Year 1983; March 1984.

Table 10 shows how the total net economic value of the OCS oil and gas resources would be distributed under each of the three perspectives suggested above. There are relatively few differences among the three. The one exception is that Alaska's share of Federal grants to State and local governments is two to three times greater than its share of tax payments and population.

Environmental Risks and their Distribution

As stated earlier in this section, environmental risks are based on the analysis of social costs in Appendix G. While net social costs measure the estimated cost of producing an area's leasable resources to the Nation as a whole, they do not indicate the distribution of costs and in particular what the costs are to residents of each onshore area adjacent to the planning area.

The distribution of costs among the population tends to be skewed toward residents of coastal States. These people are more likely to be adversely affected by OCS development than inland residents.

To assess the costs borne by residents of coastal States adjacent to OCS areas resulting from the production of the leasable resources unleased as of January 1987, estimates were developed of regional cost. Regional cost as defined in Appendix G is a measure of the costs borne by the users of and onshore residents adjacent to an OCS planning area from OCS production in that area. The regional costs in Table 11 have been estimated by subtracting from the gross social cost associated with OCS production in an area, the compensation payments paid to residents for oil spill damages (assumed to be 50 percent of oil spill losses), and for commercial gear conflict losses (assumed to be 60 percent of all losses). Also deducted from the gross social cost associated with OCS production in an area are the costs avoided because OCS oil production in an area reduces oil imports into that area, and hence imported oil-related spills.

The production of OCS oil, though it may result in oil spills, also reduces the amount of oil imported and thus reduces the spills that would occur from tankers carrying imports in U.S. coastal waters. While the social cost analysis does not assume the backing out of imported oil by domestic natural gas production, it should be noted that OCS exploration and development can lead to the production of natural gas resources as well as oil. In 1984, about 25 percent of domestic production of natural gas was from the OCS. The discovery of natural gas resources can increase the beneficial economic and environmental effects of backing out imported oil or can result in additional benefits for two reasons: (1) OCS gas production can displace some imported oil thereby reducing imported oil-related spills; and (2) the greater availability of more OCS natural gas may lead to fuel switching from oil to natural gas, which is a cleaner-burning fuel. This effect can in turn be enhanced by the fact that the rollover of capital stock which often occurs during fuel switching results in a general upgrading of the level of efficiency with which fuel is used.

It should be pointed out that Table 11 indicates that the Gulf of Mexico Region is estimated to incur higher costs in this analysis than was estimated to be the case in the 1982 analysis. However, Table 10 indicates that the benefits which accrue to the Gulf of Mexico Region far outweigh those costs--as is the case for all Regions. In addition, as discussed above in this section, consideration of the scheduling of OCS lease sales in frontier areas further addresses the requirements of section 18(a)(2)(B) with respect to the equitable sharing of costs

Table 11. Distribution of Range of Social Costs by Region from Production of All Estimated Leasable Resources Unleased as of January 1987 (Millions of 1987 Dollars)

Regions	Regional Costs/a
I. Maine, New Hampshire Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia	-1.29[b] to -1.77[b]
II. North Carolina, South Carolina, Georgia	0.75 to 1.35
III. Florida	5.84 to 8.07
IV. Texas, Louisiana, Mississippi, Alabama	27.90 to 17.29
V. California	24.47 to 31.42
VI. Washington, Oregon	-0.17[b] to 0.76
VII. Alaska /c	4.31 to 28.52

/a The regional cost is estimated on a planning area basis as the gross social cost estimated to result from the production of that area's resources minus compensation pursuant to provisions of the OCS Lands Act Amendments of 1978 for potentially resultant oil spill and commercial fishing gear conflict losses, and minus the social cost avoided when oil production in the area backs out oil imports to the area (see Appendix G). Regional costs are calculated to include the costs associated with transshipment of oil produced in other OCS areas to or through that one OCS area. These planning area figures are allocated as follows: where a Region's coastline corresponds to one or more planning areas, for example, California, the total costs from the adjacent planning areas are allocated to the Region by adding them together; where adjacent planning areas do not coincide with State offshore boundary extensions, costs are allocated to Regions in proportion to their State coastline mileages.

/b A negative estimated regional cost, e.g., $-1.29 million dollars, indicates a gain rather than a loss in those values analyzed. Such net benefits result and accrue to the residents of the States adjacent to the planning area when the regional costs associated with development of the area's resources are less than the oil spill costs foregone from "backing out" foreign crude oil imported in tankers.

/c The wide variability in regional costs for Alaska occurs because only Navarin Basin has leasable resources at the $19 per barrel starting price. See Table 8 in Appendix F.

vis-a-vis mature production areas such as the Gulf of Mexico. Finally, in the context of the benefits to the Nation as a whole, Tables 1, 2, and 3 make clear the loss to the Nation which could result from unduly restricting oil and gas leasing in the Gulf of Mexico.

In conclusion, the developmental benefits of OCS leasing are shared widely while the environmental risks are concentrated in regions adjacent to the areas of the OCS in which most of the unleased oil and gas resources are expected to be leased and produced. The uneven burden of environmental risk should be reduced substantially by compensation that will be provided to those suffering damages from oil spills and commercial fishing gear losses. Further reductions in the unevenness of environmental risk could be achieved by increasing compensation, by imposing stricter controls or stipulations, or by restricting leasing in areas of higher environmental risk. As noted above, however, the court found that restricting leasing in frontier areas can lead to an inequitable sharing of environmental risks (California v. Watt (II) at 599). In addition, restrictions would need to be substantial in order to change markedly the distribution of environmental risk. Such restricted leasing would, however, substantially reduce benefits to the Nation as a whole.

II.D. Balancing Considerations

Section 18(a)(3) requires that:

> "The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."

In California v. Watt (II) (at 606), the court upheld the cost-benefit analysis used in the formulation of the July 1982 5-Year OCS Oil and Gas Leasing Program as a means of compliance with section 18. In that 1982 analysis, as in the current analysis, the general interpretation of this requirement is that there is a presumption that an area should be included on the schedule if the expected benefits of oil and gas activities there exceed the expected costs, and that the most valuable areas should be offered first and most frequently. Estimates of the benefits from discovery and production of oil and gas and of the social costs, including a consideration of the factors listed in section 18(a)(2), have been calculated as discussed in Part II.B and Appendices F and G. These estimates have been used to calculate estimates of the net social value by planning area.

Net social value is the difference between the net economic value and the social cost estimated for total production of an area's unleased leasable resources, assuming that all are leased as of January 1987 and developed in the narrowed timefram thereafter. Table 12.1 displays the variation of estimated net social value by planning areas for the $19 to $29 range of starting oil prices. Table 12.2 balances benefits and costs on a per barrel basis for low value areas for which the method used for Table 12.1 was not applicable.

The presumption that areas with positive net social value estimates are to be included on the schedule is subject to modification based on the qualitative information not included in the quantitative net social value calculation. Such qualitative information appears in Part II.A, Part II.B.3, and Appendices B, C, H, I, and J. Further qualitative information will be contained in the EIS.

Careful examination of section 18(a)(3) and the methods used in the calculation of net social value indicates that the three considerations to be balanced ("the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone") are not mutually exclusive. For example, there is an overlap between the potential for adverse impact on the coastal zone and the potential for environmental damage. Also, increased domestic production of OCS oil and gas can cause environmental damage and adverse impacts on the coastal zone--but can also reduce tankered imports of oil and thus reduce the potential for environmental damage and adverse impact on the coastal zone. The discovery of OCS natural gas in particular has the added potential for environmental and efficiency improvement, as discussed above with respect to equitable sharing. Furthermore, the beneficial effects which rigs can have as fishing reefs in some areas also shows that there can be gains which can offset to some extent the potential social costs of production.

It is worth reiterating that the section 18 analyses have been conducted such that the net economic benefits of leasing tend to be understated and the social costs of leasing tend to be overstated. In addition, it is noteworthy that even if social costs were 17 times greater, net social value would remain positive for all the areas listed.

Table 12.1

Estimated Net Social Value of Total Production of Unleased Undiscovered OCS Oil and Gas Resources as of January 1987 by Planning Areas Showing Variation by Starting Oil Prices (@ $19 to $29 per barrel) /1

Planning Area	Column 1: Variation of Estimated Net Economic Value of Leasable Resources ($ 1987 Millions) (1A) @$19	Column 1: (1B) @$29	Column 2: Variation of Estimated Social Cost of Producing Leasable Resources ($ 1987 Millions) (2A) @$19	Column 2: (2B) @$29	Column 3: Variation of Estimated Net Social Value ($ 1987 Millions) (1A-2A) @$19	Column 3: (1B-2B) @$29
Central Gulf of Mexico (E)	$17,860	$35,245	$40	$41	$17,820	$35,204
Western Gulf of Mexico (E)	14,506	31,299	29	29	14,477	31,270
Southern California (F-E)	3,975	9,088	17	20	3,958	9,068
South Atlantic (P-F)	839	3,022	3	5	836	3,017
Central California (P-G)	765	2,649	5	6	760	2,643
Northern California (P-G)	910	2,463	5	6	905	2,457
Eastern Gulf of Mexico (G)	675	2,379	5	6	670	2,373
Navarin Basin (F-G)	121	2,591	7	27	114	2,564
Mid-Atlantic (G)	198	723	1	2	197	721
Washington-Oregon (P)	207	454	*	1	207	453
Beaufort Sea (F-G)	*	678	*	6	*	672
St. George Basin (G)	*	464	*	3	*	461
North Atlantic (G)	85	258	1	1	84	257
Straits of Florida (P-F)	14	33	*	*	14	33
Chukchi Sea (P)	*	596	*	5	*	591
Gulf of Alaska (F-G)	*	33	*	*	*	33
North Aleutian Basin (G)	*	20	*	*	*	20
Norton Basin (F-G)	*	20	*	*	*	20
Kodiak (G)	**	**	**	**	**	**
Hope Basin (F)	**	**	**	**	**	**
Shumagin (VP)	**	**	**	**	**	**
Cook Inlet (G)	**	**	**	**	**	**

*Estimated to be less than 0.5 million $1987.

**Resources for these areas are estimated to be negligible (see Table 2), thus no production is expected, and social costs are estimated to be less than 0.5 million $1987. (See Table 12.2 for the balancing of benefits and costs of OCS leasing and production for these areas).

/1 See Figure 1 of this SID and Appendix F for the basic assumptions and results of the net economic value analysis and Appendix G for the basic assumptions and results of the social cost analysis. The planning areas are ordered in this table by net economic value @ $24/bbl.

In parentheses after each planning area is the evaluation of the grid coverage/quality of geologic and geophysical data for regional resource estimates for that planning area: E = Excellent; G = Good; F = Fair; P = Poor; and VP = Very Poor (see Appendix E)

Table 12.2

Balancing of Benefits and Costs
in Low Value Planning Areas /1

	Estimated Net Economic Value Per Barrel (Appendix F, Table 6A)	Estimated Social Costs Per Barrel (SID Table 8)
Cook Inlet	$1.44	$0.02
Shumagin	1.34	0.01
Kodiak	1.25	0.01
Hope Basin	0.68	0.01

/1 This table indicates the estimated balance of costs and benefits for planning areas estimated to have some developable resources, but only negligible leasable resources. Since the balancing analysis presented in Table 12.1 depends on the presence of estimated leasable resources in a planning area, a different method had to be used to estimate the balance of costs and benefits of OCS leasing and production for these four areas.

This table is based on the assumptions that if some or all of the developable resources in these areas were leased, their expected private value (the after-tax net present value for the bidder) would have to be equal to or greater than zero; that--on the low side--private value is equal to zero for each of those planning areas; and that the starting oil price is $24/bbl. (See Appendix F.)

Furthermore, both the total benefits and the costs are the result primarily of the resource potential of an area. There are no areas in which the estimated resource potential is substantial while the estimated costs of environmental damages and adverse impacts on the coastal zone are greater than the estimated benefits. On the contrary, in every planning area for which there are estimated leasable resources, estimated net economic value is at least 17 times larger than the estimated social costs. Areas of low resource potential have low benefits and even lower costs. Should such areas turn out to have more oil and gas than estimated, both the benefits and the costs would be greater than estimated. Still, the estimated benefits (see Tables 5, 8, and 12.2) would exceed the estimated costs. Thus, areas in which the estimated resource potential and estimated economic benefits are low to negligible should not be regarded as areas in which the costs exceed the benefits.

The timing and location of sales in the alternative schedules presented in this SID depends on numerous considerations which are discussed in connection with the decision options in Part III of the SID.

The court in California v. Watt (II) (at 712) specifically upheld the scheduling of lease sales on the basis of section 18 interests other than relative net social value alone. Indeed, in this context it should be noted that section 18(a)(3) specifies that one of the three elements to be balanced is "the potential for the discovery of oil and gas" (emphasis added). The great dependence of knowledge about the location and size of oil and gas deposits on drilling information needs to be recognized in the use of the net social value rankings which are in turn based on resource estimates. Resource estimates generated by the Government and by private parties are subject to substantial uncertainty especially where there is a paucity of seismic and drilling information available for an area (see Appendix E). This makes resource estimates about frontier areas especially uncertain. It is quite possible that estimates of resource potential based on very little data for a frontier area will turn out to be much lower than estimates based on more intensive seismic data. The collection of seismic data is the first step in the process leading to discovery of oil and gas. It results primarily from investments by firms planning to bid in scheduled lease sales. The scheduling of a sale for a low potential frontier area for which little data are available is one way to expedite a more intensive evaluation of its resource potential. Indeed, one of the purposes of the 1978 OCS Lands Act Amendments is to "insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time" (section 102(9)). Consequently, although resource estimates are our best indicator of where the search for oil and gas should be focused, it is reasonable not to rely on the resulting net social value calculations alone in scheduling sales in frontier areas.

Planning areas have also been analyzed in terms of relative environmental sensitivity and marine productivity (see Part II.B.3 and Appendix I). To the extent possible, these considerations are reflected in the net social value rankings. However, since many of the environmental considerations can only be viewed in qualitative terms, the environmental sensitivity and marine productivity rankings need to be reviewed separately, as well as being an input to the estimation of net social value.

In addition to being used in the context of the factors discussed above, the net social value estimates are not used directly, but are used as a basis for the

formation of groups of areas within a range of estimated net social value, as appears below. Such an approach further guards against overreliance on the the absolute values of the net social value estimates, whose limitations have been described above in Part I and in Appendices F, G, and S.

The relative net social value estimates displayed in Table 12.1 can be used to divide the planning areas into the following three groups, based on magnitude:

High	Central Gulf of Mexico, Western Gulf of Mexico.
Intermediate	Southern California, South Atlantic, Central California, Northern California, Eastern Gulf of Mexico, Navarin Basin, Mid-Atlantic, Washington-Oregon, St. George Basin, Beaufort Sea, North Atlantic, Straits of Florida, Chukchi Sea, Gulf of Alaska, North Aleutian Basin, Norton Basin.
Low	Kodiak, Hope Basin, Shumagin, Cook Inlet.

The entire ranges of variation of net social value figures by oil starting prices within the Intermediate group (from less than \$0.5 to \$3,958 [@ \$19/barrel] and from \$20 to \$9,068 [@ \$29/barrel] [both in millions of \$1987]) are substantially less than (i.e., less than 30 percent of) the net social value figure for the lower value area in the High group at the corresponding oil prices (Western Gulf of Mexico: \$14,479 and \$31,272, respectively [both in millions of \$1987]).

The areas in the Low category include those which have been estimated to have negligible net economic value of leasing throughout the variations of starting oil prices, \$19 - \$29 (see Table 2). Kodiak, Hope Basin, Shumagin, and Cook Inlet, however, have been estimated to have some developable resources (see Table 4).

Part III identifies the numerous considerations which bear on the timing and location of sales. On the basis of net social value alone, the following timing would be consistent with this grouping:

--Areas in the High group are clear candidates for annual offerings.

--Areas in the Intermediate group have net social values substantially lower than the High group but all above \$20 million (\$1987) within the variation of starting oil prices of \$19 - \$29 per barrel. In this Intermediate range of areas, substantial discretion could reasonably be exercised within the bounds of section 18 considerations concerning the pace of leasing and the scheduling of sales. Sales in this group could be offered on a biennial, triennial, or less frequent basis, and could be scheduled as standard or frontier exploration sales. A frontier exploration sale is one for which industry interest would be polled by means of a Federal Register Notice several months prior to the scheduled beginning of the standard presale process.

--Areas in the Low group are candidates for standard sales, frontier exploration sales, or deferral for reconsideration in the formulation of the next 5-year program.

The Secretary will need to consider the conclusions which can be drawn from the net social value estimates and rankings, collectively with the information discussed above and the other qualitative information presented in this document and its appendices.

II.E. Minimum Bid and Bid Adequacy Review Considerations

Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires the formulation of an OCS oil and gas leasing program consistent with the following principle:

> Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

In litigation on the 1982 5-year program, the U.S. Court of Appeals for the District of Columbia Circuit was asked to determine whether the Secretary could meet the statutory requirement "to assure receipt of fair market value for the lands leased and the rights conveyed" by OCS oil and gas leases, in light of the fact that the "accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts." The court ruled that, despite the lower bids expected, "the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received. The statute requires nothing more." (See California v. Watt (II))

The structure of the lease market for the exchange of these rights between buyers and sellers is established by the OCS Lands Act. The act provides that oil and gas leases are to be sold by competitive sealed bidding and thus establishes the requirement of a competitive market structure to generate the value of OCS oil and gas leases. The decision to accept the high bid is based only on the amount of the bid (relative to the MMS quantitative measures of bid adequacy) given that the high bidder is qualified to conduct OCS operations (see Appendix K for a detailed discussion of fair market value).

The Natural Resources Defense Council and others, in their comments on the Draft Proposed Program included concerns about fair market value issues. Specifically NRDC contends that areawide leasing is not likely to lead to an efficient allocation of resources or the attainment of fair market value for the resources leased. They believe that the decline in per acre bonuses indicates that the Government did not receive a fair market value for the resources leased. They attribute this decline to a decrease in competition with areawide leasing, limited resources available to bid and to formulate bids, and the limited information about the tracts offered. NRDC's and others' concerns regarding the revenue effects of past areawide leasing are addressed in Appendix P, which analyzes both the tract selection and areawide leasing approaches.

In comments on the Draft Proposed Program, NRDC also expressed concern about the Department's ability to do an effective job of evaluating tracts for bid adequacy. Bid adequacy procedures originally adopted in conjunction with areawide leasing have been modified as a result of ongoing analysis of their use. As a result of these modifications, the percentage of tracts passed to "Phase 2" (of the bid adequacy procedures) for detailed evaluation, has increased from 33 percent to over 50 percent. In its March 26, 1985, report, "Interior Has Taken Steps to Improve the Adequacy of Data Used for Making (OCS) Leasing Decision," the GAO discussed the issue and made no recommendations. For the Proposed Program, Appendix K has been revised to include a complete description of the current bid adequacy review procedures with an explanation of how these procedures help to ensure the receipt of fair market value.

Another factor which NRDC believes contributes to the failure to attain fair market value is the Government's use of the cash bonus bid form of auction. NRDC proposes that alternative bidding systems be considered for their roles in ensuring the receipt of fair market value.

Alternative bidding systems have currently not been addressed in terms of their effects on competition and fair market value. Based on past analysis of these systems, the Department has found that the effects on competition have been negligible. (See: DOI, MMS: "Report to Congress on Fiscal Year 1983 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems", April 1983.)

Minimum Bid and Bid Adequacy Review

The competitive sealed bidding process of the OCS lease market is the market mechanism which generates a fair market value at a specific point in time (i.e., a sale). However, there are circumstances in the OCS lease market which could allow bids to be submitted which, without the exercise of a prudent assessment by the Government, could result in receipt of less than fair market value. Where information asymmetry exists, such as on drainage and development tracts on which the adjacent owner has privileged information, or on wildcat and proven tracts that involve development technologies unique or limited to selected companies, the corresponding bid may be skewed and other parties may choose not to bid. In order to assure fair market value as the law requires and the courts have interpreted, the Secretary has developed a set of procedures which reflect an understanding of the workings of the OCS lease market in generating values and bids. The Secretary has structured the procedures to assure receipt of fair market value by relying on the market to generate fair market value and by relying on Government evaluations to assure that market values being generated for certain categories of tracts are indeed fair; otherwise, the high bids are rejected and the tracts reoffered at a later date.

In July 1982, a Department-wide task force was established to develop and test various methods for determining bid adequacy in light of the Secretary's legal requirement to assure receipt of fair market value in conjunction with the leasing program proposed at that time. In February 1983, the Department adopted the recommended procedures of the task force. The procedures consisted of a two-phase bid adequacy process which used tract classification and actual bid data to determine which tracts required detailed analysis. Phase 1 includes market-oriented evaluation criteria for accepting some bids on some blocks and determining what other bids will receive further evaluation in Phase 2. Phase 2 uses tract value estimates from a discounted cash flow model as the basis for accepting or rejecting bids.

In 1982, the Department increased the minimum bid from $25 to $150 per acre and provided for reconsideration of the minimum bid level based upon experience. In conjunction with the two-phased procedures, the minimum bid may help to assure fair market value by substantially increasing the bonus amounts bid on many one-bid tracts. The minimum bid represents an across-the-board Government evaluation standard with which all high bids are compared--it provides the initial step in the overall bid adequacy screening process.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. On the surface, there has been an observable overall decrease in the average bonus bid per acre in recent years. This trend actually began in 1982 in tract selection sales. There has also been an increase in the number of one-bid tracts. Analysis of these observations was made to assess their cause. While the per acre bonus declines have been due to a myriad of factors, the most significant ones appear to be the decrease in the expected price of oil and the overall quality and location of tracts being offered for lease. A 20 percent drop in the real world price of oil, along with projections of lower rates of future price growth, have significantly influenced the present value of tracts being offered. Further, the sale and leasing of tracts in areawide offerings have seen industry moving into deep-water, high-cost areas of mature OCS planning areas and into high-cost frontier areas--a trend which had barely begun when nomiration-type sales were held. Market forces are operating to reflect these conditions.

Based on analyses, studies, and experience with the oil and gas leasing market, categories of tracts for which the bids may not assure fair market value are subjected to additional independent Government evaluation. All evaluations incorporate the use of the latest geological, geophysical, and economic evaluation methodologies and account for the inherent uncertainties of all the major variables. A detailed description of bid adequacy review procedures appears in Appendix K.

Part of the decision on the Draft Proposed Program was to review the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas. Alternatively, the question was raised whether enlargement of the maximum tract size would achieve effects comparable to varying the minimum bid. Two of the eight topics presented for comment in the Federal Register Notice of March 22, 1985, pertain to these questions. The following comments were received on these topics:

Federal Register Notice Topic No. 6:

> Whether conditions such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.
>
> The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the minimum bid level, it would be best to leave it as is for the sake of program stability.
>
> Alabama stated that the current minimum bid level is appropriate only for frontier areas and should be raised in high potential areas. Maryland commented that the minimum bid level should be adjusted, at least on a planning area basis, to take care of any contingencies that may arise. New Jersey communicated a willingness to explore with the Department of the Interior consideration of varying the current per acre bid level if it could be demonstrated that it would be an economic benefit to the Federal Government and encourage exploration.

North Carolina stated no objection to raising the minimum bid level, but would object to lowering it. Rhode Island endorsed establishment of different minimum bids for different planning areas. The State also suggested offering a limited number of tracts under a work commitment/fixed royalty bidding system. Virginia commented that the factors under consideration with this topic could have an effect on minimum bid level.

Chevron and Marathon commented that the current minimum bid is satisfactory for a 5,760 acre tract, but should be lowered for larger tracts. BP Alaska commented in favor of reassessing the minimum bid considering reduced expectations for future oil prices. ARCO encouraged elimination or reduction of the current minimum bid and recommended establishment of a minimum bid for each planning area at a level commensurate with exploration risk for that area.

Shell recommended lowering the minimum bid in all planning areas and pointed out that the bonus bid represents just one element of the total revenue received by the Federal Government as a result of the OCS program. They also commented that the minimum bid level should be low to offset risks and costs in frontier areas and make leasing and developing those areas viable. Tenneco suggested halving the current minimum bid in the Gulf of Mexico to enhance the economic viability of prospects on which the potential for hydrocarbons is less than that of leases offered in previous sales.

Sohio commented that generally the minimum bid level should be lowered, and recommended specific levels for certain planning areas and conditions. Texaco expressed opposition to the current minimum bid level and suggested that a range of $25 - $50 per acre be adopted on a nationwide basis. Exxon recommended that the minimum bid level be revised on a planning area and water depth basis. A figure of $50 per acre for Alaska planning areas and greater than 400' water depths was suggested, and a level of $75 per acre was suggested for the rest of the OCS.

The Lone Star Sierra Club chapter (Galveston, Tx.) stated that the minimum bid level should be tied to the economy by indexing, and difficulty factors such as deep-water and strong currents should be considered, but the minimum bid always should be enough to cover costs of the leasing program. The Florida Public Interest Research Group and Greenpeace expressed opposition to lowering the minimum bid level.

Federal Register Notice Topic No. 7:

Whether the tract size limit of 5,760 acres ought to be expandeo; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid.

The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the maximum tract size, it would be best to leave it as is for the sake of program stability.

Alabama stated that the maximum tract size should not be expanded for tracts in the 8(g) zone off Alabama, and sufficient data are not available to comment on expansion in areas beyond the 8(g) zone. Virginia stated they have no reason to advocate a change in tract sizes at this time. New Jersey communicated a willingness to explore with the Department of the Interior consideration of expanding the maximum tract size if it could be demonstrated that it would be of economic benefit to the Federal Government and encourage exploration. North Carolina commented that expanding the maximum tract size may be appropriate for frontier areas, but not for highly productive areas.

BP Alaska, Shell, Texaco, Amoco, and Exxon did not support expanding the maximum tract size. BP Alaska commented that larger tracts might lower competition. Shell recommended encouraging the formation of exploration units rather than leasing larger tracts. Chevron, Sohio, and Mobil supported expanding the maximum tract size to tailor it to specific prospects. Chevron recommended sizes up to 23,040 acres in the Atlantic Reef Trend and West Florida Strait. Mobil recommended increasing the size of tracts in waters over 300 meters deep to 11,520 acres. Marathon commented that a larger tract size may be appropriate in low interest areas or areas where exploration and development costs are high.

The Florida Public Interest Research Group stated no objection to enlarging tract size to a reasonable economic production unit, providing the minimum bid level is raised to maintain the same price per acre. Greenpeace expressed opposition to expanding the maximum tract size.

MMS has also conducted evaluations of both the minimum bid and larger tract size issues:

1. Analysis of Minimum Bid Policies, Branch of Economic Studies, Offshore Resource Evaluation Division, June 7, 1985; and

2. Evaluation of Larger Tract Size Options, Branch of Economic Studies, Offshore Resource Evaluation Division, June 1985.

Both papers have been considered as part of the record for the development of the new 5-year program. The larger tract size paper is also discussed below and the minimum bid paper is summarized in Appendixes F and K, and is discussed in the decision options section of this SID.

The larger tract size analysis focuses on the possibility of modifying the current maximum tract size of 5760 acres as a means to stimulate industry activity in high-risk OCS areas by providing a new incentive for industry to explore these areas. The reasoning here is that, in high-risk, high-cost areas, the present tract size may not be appropriate to support investment costs even if a discovery were made. The Secretary has the authority, under section 8(b)(1) of the OCS Lands Act, to increase the maximum tract size (beyond 5760 acres) if a larger area is necessary to comprise a reasonable economic production unit.

In general, benefits of larger tract sizes include: a decrease in discovery risk; economies of scale; greater information value; and a reduction in production risk, if a discovery is made. Each of these benefits is described in the analysis. However, the analysis also details significant problems associated with increasing tract size, including the determination of a "reasonable economic production unit." Defining a "reasonable economic production unit" would be a complex task, because of the many factors which influence the determination and because these factors change through time and vary among areas. Additionally, the acquisition of the information would be costly and would need to be collected on a repeated basis. Another important factor to consider is that what is perceived to be a reasonable economic production unit, even for a given geologic prospect, is likely to differ among lessees. Therefore, even if the Government could identify a specific structure and define a reasonable economic production unit, lessees may not share the same view.

The implication of the analysis is that increasing tract size may not be the most efficient policy instrument with which to provide exploration incentives because of two major factors: complexities associated with trying to determine a reasonable economic production unit; and the fact that unitization is available to help lessees achieve economies of scale in exploration, development, and production. For these reasons, and because a significant number of public comments (including industry) indicated a preference for tracts no larger than 5760 acres, an option to increase tract size is not presented in this SID.

A decision option on minimum bid policy is developed, which includes a discussion of the effects of the minimum bid level on:

1. bidding and Government receipts;

2. the appropriate timing for the leasing and development of prospects in different OCS areas; and

3. promoting exploration in high-risk/high cost areas.

This decision option and a decision option for bid adequacy procedures appear in section III.C.

Part III Options for the Proposed Program

Section 18 provides for three successive stages of development of a new 5-year OCS leasing program prior to final approval. This Proposed Program stage is the second of those three. No final decisions on the new program will be made until after completion of the process set forth in section 18 and the National Environmental Policy Act and their implementing regulations.

III.A. Location and Timing Options for the Proposed Program

In the formulation of a leasing program, many location and timing considerations merge. Consequently, this section of the SID presents a number of location and timing issues in combined form.

The first category of location considerations in formulating the Proposed Program concerns the selection of a configuration of planning areas and boundaries. The second category deals with the scheduling of sales in the various planning areas.

A.1. Planning Area Configuration Options for the Proposed Program

The development of a new 5-year program calls for the consideration afresh of the whole OCS. The configuration of planning areas rests on a number of considerations: geological and geophysical data; leasing, exploration, development, and production history; environmental data; coordination with coastal governmental entities; mapping considerations; jurisdictional claims to the OCS and the Exclusive Economic Zone (EEZ); and administrative factors.

The March 1985 Draft Proposed Program divided the entire OCS into 26 planning areas which are basically similar to the areas adopted for the 1982 program, except for the following new features: the planning areas offshore California were reconfigured from two to three; a separate planning area was established for the Straits of Florida; the Eastern Gulf of Mexico and Beaufort Sea planning areas were reconfigured; and 128° W. longitude was proposed as the seaward boundary for the new Northern California and Washington-Oregon planning areas. The California planning areas were reconfigured to the following:

1. Southern California--the offshore area from the provisional boundary with Mexico north to the San Luis Obispo County/Monterey County line, between block rows N825 and N826. This would merge the Santa Maria area with the present Southern California area. This new area would contain approximately 436 miles of mainland coastline.

2. Central California--the offshore area north of the San Luis Obispo County/Monterey County line to the Sonoma County/Mendocino County line, between block rows N894 and N895. This new area would include two basins and would contain approximately 350 miles of mainland coastline.

3. Northern California--the offshore area north of the Central California area to the California/Oregon border. This new area would include the two northernmost basins and would contain approximately 286 miles of mainland coastline.

Comments

General: The State Department discussed the international aspects of planning area configuration, suggesting revision of the boundaries delineated for the North Atlantic, South Atlantic, Straits of Florida, Western Gulf of Mexico, Washington-Oregon, and Chukchi Sea planning areas. These suggestions have been incorporated into decision option 1-a. The Natural Resources Defense Council (NRDC) suggested that planning areas be more narrowly defined and requested an explanation of the proposed reconfiguration. A discussion of the environment of the planning areas as reconfigured will appear in the draft EIS for the new program.

Alaska: The National Oceanic and Atmospheric Administration (NOAA) expressed concern that several Alaska OCS planning areas may extend beyond foreseeable technology and economics and called for the environmental studies program to examine the deepwater areas closely before actually deciding to lease them. BP Alaska and the National Ocean Industries Association (NOIA) specifically endorsed the proposed configuration of the Beaufort Sea planning area.

Atlantic: New York and Rhode Island reiterated the desire to be able to review proprietary data from both the North Atlantic and Mid-Atlantic planning areas (see Option 1-b). Delaware reiterated a suggestion to reconfigure the boundary between the Mid-Atlantic and North Atlantic planning areas in a different way. Maryland, New Jersey, and Virginia stated their agreement with the proposed configuration of planning areas. Marathon Oil endorsed establishment of the Straits of Florida planning area, and Texaco endorsed the South Atlantic planning area. Florida expressed concern about making the Straits of Florida a distinct planning area. North Carolina found the planning areas to be appropriate, but expressed a concern for more study of the Straits of Florida planning area. Exxon supported the proposed configuration of all planning areas except the Straits of Florida, the separation of which they believe is of no practical value. The API shared this opinion of the Straits of Florida planning area. The Florida Public Interest Research Group stated they have no objection to the proposed configuration of planning areas, but are concerned by the creation of the Straits of Florida area.

California: The U.S. Environmental Protection Agency (EPA) requested additional discussion of the reconfiguration of the California planning areas. A discussion of the environment of the California planning areas will appear in the draft EIS for the new program.

The County of Santa Cruz submitted comments stating that the reconfigured planning areas will enable more comprehensive and accurate environmental assessment of the Central California Basin. The County of Ventura concurred with the March 1985 reconfiguration of planning areas. The City of San Francisco stated that the California OCS planning areas as reconfigured in March 1985 should allow more concentrated review of leasing issues. The County of San Luis Obispo submitted a resolution expressing support for the March 1985 reconfiguration of California OCS planning areas with the exception of expansion of seaward boundary limits. The March 1985 reconfiguration of California OCS planning areas was endorsed by NOAA. Chevron, Amoco, BP Alaska, Marathon, Shell, Texaco, Western Oil and Gas Association, American Petroleum Institute (API), and NOIA concurred with the proposed configuration of planning areas and specifically endorsed the reconfiguration of California OCS planning areas. Get Oil Out, Inc., stated that the reconfiguration of California OCS planning areas provides a more equitable leasing

On the other hand, the California Department of Justice stated that OCS planning areas are still too large and reiterated its request for eight planning areas offshore California. The same commenter also argued, however, that too many sales were scheduled offshore California. Thus, increasing the number of planning areas offshore a particular region of the U.S. must be considered in light of potential objections about the number of sales that would be scheduled for the region as a whole. The comment that the planning areas are too large to manage is also relevant to the question of potential deferrals of portions of planning areas, discussed below.

The California Coastal Commission objected to the establishment of three planning areas with the Santa Maria Basin placed in the Southern California planning area. They cited ecological criteria and planning burdens as the basis for objection. The California Department of Fish and Game recommended that the Santa Maria Basin be included in the Central California planning area or established as a separate planning area. The California State Lands Commission noted great biological and oceanographic differences within the proposed Southern California planning area due to moving its boundary northward. Several members of the Senate Rules Committee of the California Legislature submitted a letter making alternative proposals concerning the Southern California planning area.

Several California local governments noted the reconfiguration of California OCS planning areas in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Morro Bay, County of San Luis Obispo, City of Santa Cruz, and City of Watsonville. The City of Pismo Beach submitted a resolution recommending reconfiguration of the California OCS by placing the Santa Maria Basin in a Central California planning area extending from Point Arguello to San Francisco Bay. The City of Los Angeles stated that enlarging the Southern California planning area will decrease the possibility of performing detailed environmental analysis of the area. The City of Monterey's comments included a statement by a member of the Board of Supervisors that the California OCS planning areas will still be too large. The City of San Clemente alleged that reconfiguration of California OCS planning areas increases the overall size of the area under consideration for lease.

The Marin Conservation League and the California Public Interest Research Group noted the reconfiguration of California OCS planning areas in a resolution stating general opposition to the Draft Proposed Program. The Environmental Center of San Luis Obispo County commented that the proposed reconfiguration of California OCS planning areas serves only to divide and dilute public input to the leasing process. The League of Women Voters of San Luis Obispo County commented that planning area boundaries have been extended beyond areas of technological capability. The Pacific Coast Federation of Fishermen's Associations commented that the proposed planning areas are too large. The Santa Lucia Sierra Club Chapter stated that California should be divided into four or five planning areas. A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon R. Panetta stated that they hope the March 1985 reconfiguration of California OCS planning areas will facilitate more adequate environmental and economic impact assessments.

Gulf of Mexico: Florida opposed the expansion of the Eastern Gulf of Mexico planning area to include both the sensitive area south of 25° N latitude to 24° N latitude (near the Florida Keys) and the area east of 82° W longitude (offshore Monroe County, FL). Mobil Oil proposed moving the deepwater boundary between the Central and Western Gulf of Mexico planning areas west to represent an extension of the current Texas/Louisiana offshore shelf boundary.

Washington-Oregon: Oregon requested no leasing beyond 125° W longitude and Washington requested that sales be confined to the area of hydrocarbon potential. The discussion of subarea deferrals will respond to the comment from the State of Oregon, and the discussion of the presale process will apply to the comments of both Oregon and Washington that the OCS planning area adjacent ot them extends too far seaward. NOIA endorsed the 128° outer boundary of the Northern California and Washington-Oregon planning areas.

-Decision Options for the Proposed Program

Based on further review of planning area configuration and boundary issues, including a review of the comments on the Draft Proposed Program, the following decision options are presented for consideration.

OPTION 1-a Use the configuration of planning areas and boundaries adopted for the Draft Proposed Program, with minor adjustments recommended by the Department of State (described in Appendix N).

The boundaries selected for the Draft Proposed Program are depicted in Part I.A.5 of this SID. The minor adjustments recommended by the Department of State (listed below) do not alter those maps at the scale at which they are drawn.

North Atlantic: Extends South from the juncture of the territorial sea at 71° W longitude to 39° N latitude thence east to the juncture of an extension of the U.S.-Canada Maritime Boundary thence northerly along that line and the maritime boundary to the territorial sea thence following the territorial sea to the point of origin.

South Atlantic: East from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence south to 34° N latitude thence west to 72° W longitude thence south to 32° N latitude thence west to 74° W longitude, thence south to 31° N latitude thence west to 78° W longitude thence south to 28°17'10" N latitude thence west to the territorial sea limits thence north along the territorial sea to the point of origin.

Straits of Florida: East from the juncture of the territorial sea at 28°17'10" N latitude to 79°11'24" W longitude thence southwest along the line of U.S. jurisdiction to approximately 81°13' W longitude at 23°55' N latitude thence west to 83° W longitude thence north to the territorial sea abutting the Dry Tortugas thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

Western Gulf of Mexico: East from the territorial sea along the U.S.-Mexico Provisional Maritime Boundary to 93°26'42.19" W longitude thence along approximately 26° N latitude to approximately 91°55' W longitude thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°50' W longitude thence along the territorial sea to the point of origin.

Washington-Oregon: West along a line extending from the territorial sea at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence northeast along the limits of U.S. jurisdiction to 48°29'37.19" N latitude at 124°43'33.19" W longitude thence due south to the territorial sea thence along the territorial sea to the point of origin.

Chukchi Sea: East from the U.S.-Russia Convention Line along 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence generally southwest to approximately 68° 20' N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

The March 1985 California planning area reconfiguration satisfies several concerns noted in comments received on the Draft Proposed Program. The March 1985 reconfiguration combines all existing OCS oil and gas operations within the Southern California planning area, permitting a more realistic and accurate analysis of environmental effects. Also, in conjunction with the leasing schedule proposed in March 1985, the frequency of sales in each new planning area is reduced from one sale every other year to one sale every third year.

The seaward boundary of the Northern California and Washington-Oregon planning areas was set at 128° W longitude so as to comprise the area of hydrocarbon potential as estimated by MMS. MMS has reviewed this feature of the Draft Proposed Program and reaffirms the judgment that the official protraction diagrams included in these two planning areas contain acreage within the area of hydrocarbon potential. Likewise, the Eastern Gulf of Mexico area in the vicinity of the Florida Keys, south of 25° N latitude and east of 82° W longitude, is within the area of hydrocarbon potential. These areas are thus retained in the basic configuration of planning areas for this option. However, both the subarea deletion option and the presale process for specific sales provide ways of addressing objections to offering for lease acreage of concern to commenters.

OPTION 1-b Revise the boundary between the North and Mid-Atlantic planning areas.

This option is being retained in case a problem arises with the regulatory approach to providing New York and Rhode Island with the ability to review proprietary data concerning both the North and Mid-Atlantic planning areas. That approach was selected as part of the Draft Proposed Program and a proposed regulation is being prepared by MMS. Both States reiterated their interest in reviewing the data in question in their comments on the Draft Proposed Program.

This change would replace the previous boundary with a line which proceeds north along the 71st meridian to the northern edge of Official Protraction Diagram (OPD) NK 19-10, thence west along the boundary of NK 19-10 and NK 18-12 to the Federal/State boundary.

OPTION 1-c - Subarea Deferrals

Section 18(f)(1) of the OCS Lands Act provides the basis for the Secretary's consideration of "nominations for any area to be offered for lease or to be excluded from leasing." Requests for deferrals of about 100 specific geographic subareas or categories of subareas as part of the new 5-year program have come from a variety of parties. Appendix B lists all requests for deferral by States, localities, and other parties received in comments on the Draft Proposed Program. In addition, a document in the record of the development of the SID and EIS for the new program lists all subareas nominated for deferral in response to either the July 1984 or March 1985 Federal Register Notices in the new 5-year program as well as a number of Department of Defense and National Aeronautics and Space Administration use areas. That document describes the environment of the subarea, its resource potential, and the impacts which might be avoided were the subarea to be deferred from the new program. The outcome of consultations concerning OCS leasing offshore California will also be reflected in the new 5-year program.

Advantages and Disadvantages of Subarea Deferrals at the 5-Year Program Stage

On one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferrals of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, even if the prospect of leasing certain subareas is fraught with controversy, there are reasons for waiting until after the final 5-year program is issued before deciding on their deferral. The U.S. Circuit Court of Appeals for D.C. has upheld the phased nature of OCS decisionmaking, with the broadest decisions affecting whole planning areas to be made at the 5-year program stage and more specific decisions within planning areas to be made in the presale process.

Section 18 is designed to compare whole planning areas. No subarea deferrals from the midst of planning areas were made in the 1980 or 1982 programs. Neither Appeals Court opinion gives clear guidance on this issue. Given the interpretation of section 18 by the U.S. Court of Appeals for D.C. in California v. Watt (II), the requirement for a quantitative comparative analysis of planning areas significantly complicates the process of making a decision on subarea deferrals at the 5-year program stage.

If any subarea deferrals are made part of the Proposed Program, the quantitative comparative analysis of planning areas will be re-run based on the modified planning areas and the results presented for consideration for the decision at the Proposed Final Program stage. Given the way in which net social value rankings (economic benefits minus social costs) are grouped in order to structure decision options, the deferral of a substantial portion of the resources in a planning area could significantly affect its place in the 5-year program schedule options.

Subarea deferrals can short-circuit the extensive presale planning process including environmental analysis and consultation and can remove the possibility of reaching sale-specific accommodations and safeguards that could allow offering areas of concern.

Deferrals may be premature and may limit flexibility if made before the availablility of the geological and environmental information usually gathered during the presale process for a sale.

Subarea deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a 2-year process). This could have a dampening effect on information-gathering in areas which are deferred. Thus, subarea deferrals may, effectively, become permanent.

Comments on Special Consideration for Subareas/Subarea Deferrals

In addition to the requests for deferral of particular subareas mentioned above and summarized in Appendix B, a number of general comments were received. The Department of Energy commented that no subarea should be deleted from consideration until an adequate evaluation has been made of the oil and gas resource potential of the area.

Shell, Exxon, and Amoco stated opposition to establishment of special subareas subject to special considerations. Mobil and Sohio commented that frontier and deepwater areas or subareas should be given special treatment based on consideration of drilling results, economics, technology, and needs. Chevron suggested that all areas deeper than 3,000 meters be deleted from the 5-year program. Chevron also commented that portions of the Southern California planning area which are used for defense activities may require special consideration. Marathon stated that certain subareas should receive special consideration, but they should not be excluded from lease sales.

Subarea Deferral Decision Options

OPTION 1-c-i Make subarea deferrals at the 5-year program stage.

Four different approaches to deferrals are outlined below.

1-c-i-A Defer subareas based only on national security grounds--Department of Defense (DOD) and National Aeronautics and Space Administration (NASA) use areas--at the Proposed Program Stage

Section 102 of the OCS Lands Act Amendments provides that one of the purposes of the act is to "assure national security." In order to manage the resources of the OCS so as to contribute to that objective, a deferral decision could be made regarding DOD and NASA use areas only.

1-c-i-B Defer the following subareas at the Proposed Program stage.

(I) Defer eight subareas offshore California. These areas are displayed on the two maps which appear on the following pages. Other characteristics of these areas are as follows:

(a) The area off Pt. Reyes Wilderness - consists of 92 blocks and is consistent with the statutory prohibition against leasing in this area contained in section 11(h) of the OCS Lands Act.

(b) Pt. Reyes-Farallon Islands National Marine Sanctuary - consists of an area of 948 square nautical miles and is consistent with the sanctuary established by NOAA.

(c) The area in the immediate vicinity of Cordell Bank - consists of part of 8 blocks that encompass the 91 meter isobath of this area.

(d) The area offshore San Francisco Bay - consists of 16 blocks immediately outside San Francisco Bay.

(e) The areas offshore Monterey Bay - consisting of 95 blocks. These areas comprise an Area A which extends 10 miles from the California coast from just north of Monterey Bay to just south of Monterey Bay. In this 10 mile area a deferral would be made, consistent with the Secretary's statement in the Summer of 1985 and because of the potential small effect on the view from the coast. At 10 miles, a 200 foot high platform on a perfectly clear day would appear to be about 1/8 inch high and less than 1/8 inch wide. At that distance, most observers would not be able to distinguish whether the object was a platform or a ship. In Area B off Monterey Bay, the deferral is extended to include an additional area consistent with the Secretary's statement and because of current low industry interest. The combined areas extend 48 miles offshore.

(f) The areas offshore Big Sur - consisting of 449 blocks. These areas comprise an A and B zone for the same reasons as discussed with respect to the areas offshore Monterey Bay. The combined areas extend 121 miles offshore.

(g) Santa Barbara Ecological Preserve and Buffer Zone - consists of 15 full and partial blocks which were withdrawn from leasing by Public Land Order 4587 on March 21, 1969.

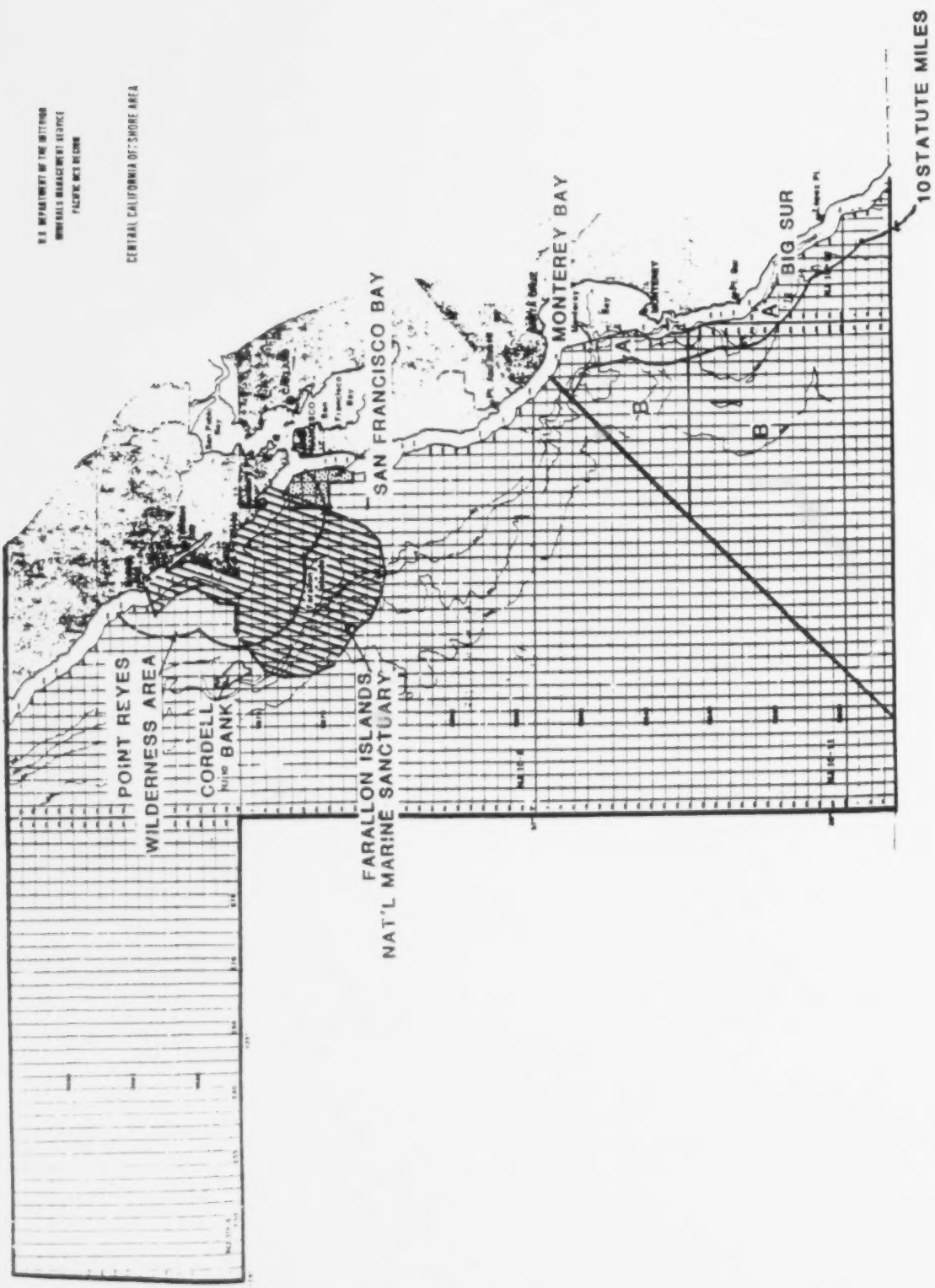
(h) Channel Islands National Marine Sanctuary - consists of about 175 blocks and was designated by a Notice published in the Federal Register by NOAA on March 30, 1981.

(II) Other

1-c-i-C Select a set of subareas for further analysis with the decision on deferral postponed until the Proposed Final Program stage. In the interim, the set of subarea deferral candidates would be analyzed further

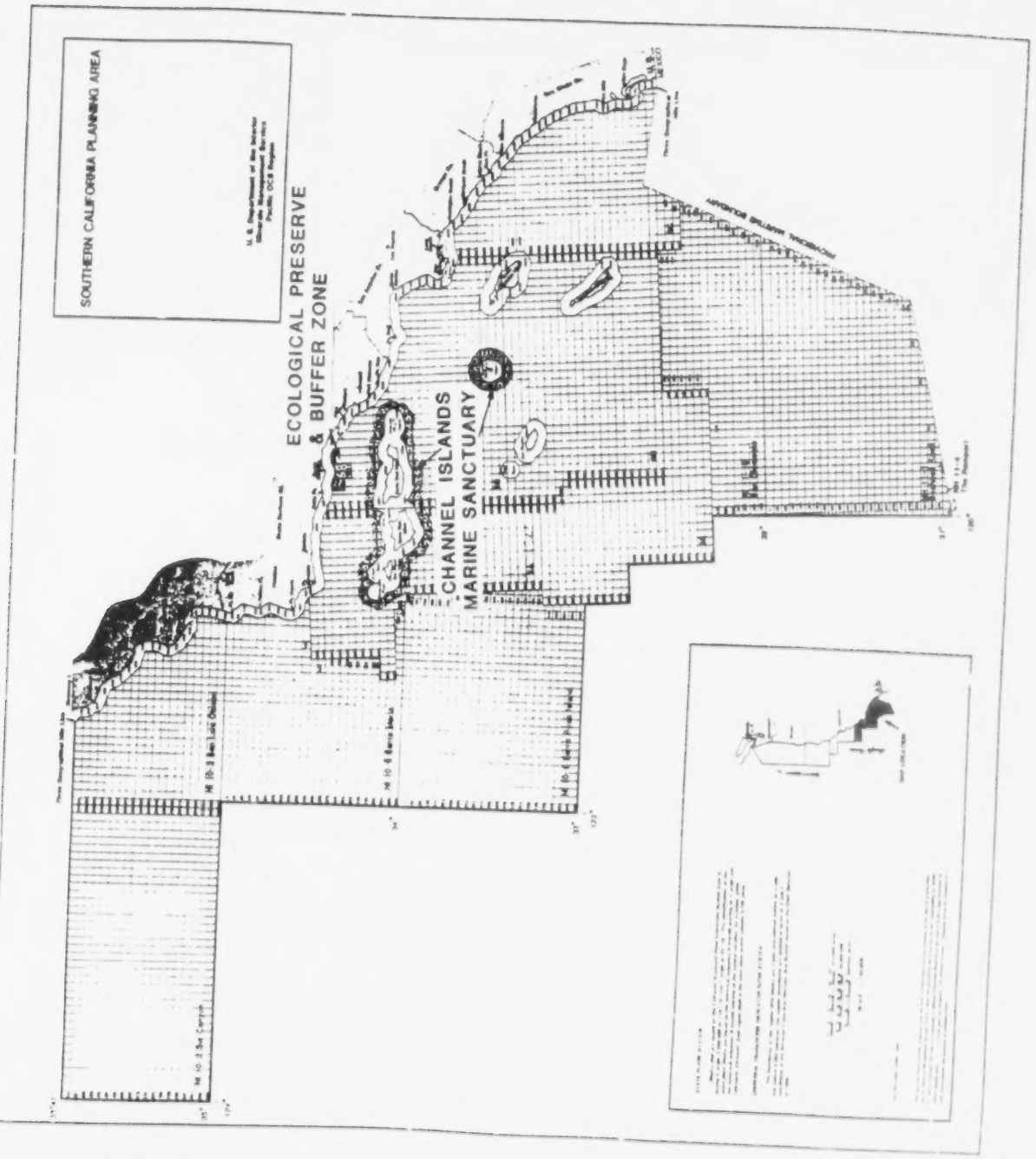
Map 3

Six of the Eight Areas Listed in Option 1.c.i.B.(I)



Map 4

Two of the Eight Areas Listed in Option 1.c.i.B.(I)



by MMS and would be submitted to the public for comments. Those subareas would then be considered for deferral as part of the decision on the Proposed Final Program.

1-c-i-D Defer all decisions on subarea deferrals to the Proposed Final Program

OPTION 1-c-ii Limit deferrals to the presale process, but "flag" subareas at the 5-year program stage for special attention during individual presale processes.

Specific subareas would be singled out in the Proposed Program for special attention (possible deferral, special lease stipulations, etc.) at Area Identification or possibly earlier at the Call stage of each sale. No section 18 comparative analysis would have to be prepared at the 5-year program stage.

"Flagging" subareas at the 5-year program stage has some of the advantages of deferrals (such as reducing some of the conflict concerning the program) while avoiding some of their disadvantages (such as the analytical problems of complying with section 18 requirements and eliminating areas before more becomes known about them during the presale process). Yet, "flagging" may be taken to prejudge the question of deferral at the presale stage.

OPTION 1-c-iii Limit subarea deferrals to the presale process without "flagging" subareas but describe the process for making subarea deferrals in the presale process at the 5-year program stage.

This option is similar to Option 1-c-ii, but no specific subareas would be singled out. The full list of deferrals recommended by commenters on the 5-year program could be cited as the type of candidates which would be considered for deferral, special stipulations, or other consideration at the Call and other presale steps.

The Area Identifications for Sale 111, Mid-Atlantic, and Sale 94, Eastern Gulf of Mexico, and the Calls for Sale 110, Central Gulf of Mexico, and Sale 97, Beaufort Sea, are examples of "focusing on promising acreage" as an alternative to both subarea deferrals and "flagging" at the 5-year program stage. Like the "flagging" option, this option could achieve a number of the objectives of deferrals without bearing the costs of premature deferrals.

Revising Planning Area Outer Boundaries

OPTION 1-d Revise the boundaries of the Northern California and Washington-Oregon planning areas to coincide with the limits of the EEZ.

This option could give exploration and geological and geophysical survey companies incentives to explore the deeper waters of the planning areas. If this option is selected, MMS will consult with the Department of State on the appropriate description of these boundaries. The EEZ line coincides with the Fisheries Conservation Zone Line and extends to approximately 129° W longitude at its furthest seaward point in these two planning areas. Washington and Oregon, on the other hand, commented that the present boundary at 128° extends too far seaward and is beyond the area of hydrocarbon potential.

2. Leasing Schedule Options for the Proposed Program

The location and timing of lease sales which comprise a 5-year OCS leasing program must be based on consideration of the factors specified in section 18(a)(2) and the balancing requirement of section 18(a)(3). The text of those sections appears in Part I, above. Part II and the supporting appendices provide the required analysis.

Section 18 Considerations

For those factors that were quantified, the resulting net social value estimates are shown in Table 12.1. As Table 12.1 shows, the social costs of OCS oil and gas activity make the net social value in each area somewhat lower than the net economic value, but do not change the ranking of the various areas by net economic value. These estimates, plus other quantitative and qualitative information and the economic guidelines set forth in Appendix F, provide a starting point for determining the location and timing of lease sales in each area (see Part II.D, above).

Once these guidelines have been reviewed, other considerations are also relevant to the scheduling of sales:

-Judgments about the degree of precision of and weight which should be attributed to estimates of relative net social value, based on such factors as

  -- The sensitivity of net economic value estimates in the base case to changes in assumptions which correspond to the possibility of changes in the world oil market, including those that could result from an oil supply disruption. This consideration relates to the net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3). The variation in starting oil prices (from $19 to $29 per barrel) and in real oil price growth rates (0 to 2 percent annually) results in a range depicted in Figure 1. Table 12.1 reflects only the variation in starting oil prices. Tables 9 and 13 in Appendix F reflect the variation of the real oil price growth rates and variation in discount rates (6 percent and 8 percent).

  -- An evaluation of the available geological and geophysical data on which the resource estimates are based (see Appendix E). This consideration relates to section 18(a)(2)(A) both in itself and insofar as it contributes to net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3).

-The history of leasing and exploration in an area (see Appendix H). This history is the source of the information which the Secretary is required to consider under section 18(a)(2)(A) and a necessary consideration for making a decision on a leasing program under section 18(a);

-The relative marine productivity/environmental sensitivity analysis considered in itself, as well as an input to the social cost analysis (see Part II.B.3 and Appendix I). This consideration is required by section 18(a)(2)(G).

-The desirability of acquiring new geological and geophysical data through exploratory work, including the drilling attendant on leasing. This consideration is specified as one of the purposes of the OCS Lands Act Amendments, which added section 18--see OCSLAA section 102(9)--and it relates to a crucial element in complying with the section 18(a) standard that the program meet national energy needs.

-The desirability of follow-up sales in areas with scheduled sales and/or existing leases. This consideration is based on the provision of section 18(a) that the leasing program be one which the Secretary determines will best meet national energy needs.

-The avoidance of drainage of unleased blocks. This consideration is based on the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed.

-Time necessary to acquire useful data from blocks leased in the preceding sale in an area. This consideration is related to the requirement that the leasing program meet national energy needs and the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed.

-Administrative considerations, including the cost of offering an area in a sale. If an area is being offered for the first time or after a long hiatus in leasing, the cost of holding a sale, including environmental studies, would be higher than in the case where funds have already been expended for studies and other presale analysis. The marginal cost of holding an additional sale in an area is estimated to be approximately $1 million. This consideration reflects the section 18(b) requirement that the Secretary include in the leasing program estimates of appropriations and staff for carrying it out. Section 18(b) makes clear the congressional view of the relevance of administrative resources and limitations to the formulation of a leasing program under section 18(a).

-Comments in response to Federal Register notices including comments of States and industry rankings of areas by resource potential and by exploration interest (see Tables 13.1, 13.2, and 13.3 on the following pages and Appendices B and D). Public comments are called for by sections 18(c) and (d). Industry comments are specifically called for by section 18(a)(2)(E).

A summary of comments on location and timing issues follows.

Location Comments

General: Alabama commented that more sales should be held outside the Gulf of Mexico to conduct a timely inventory of OCS oil and gas reserves. Louisiana and Texas commented that the proposed locations are inappropriate because they do not provide for equitable sharing of leasing among various regions. Chevron, Shell, Marathon, NOIA, Sohio, and Amoco stated general agreement with the location of proposed sales. Tenneco commented that renewed emphasis should be placed on offering leases in Alaska and California OCS regions, where the greatest potential for new resources exists. The Western Oil and Gas Association commented that because of unique and innovative exploration philosophies, high interest in an area on the part of a majority of industry members should not be

an absolute prerequisite for determining sale location. The API urged that the location characteristics of the present 5-year program be maintained in the next program. The NRDC suggested that lower resource estimates indicate that areas low in hydrocarbon potential and high in marine productivity and sensitivity should not be leased.

Alaska: The State of Alaska and NOAA stated support for the decision not to include the St. Matthew-Hall, Aleutian Basin, Aleutian Arc, and Bowers Basin planning areas in the schedule. Greenpeace opposed leasing in St. George Basin.

Atlantic: Massachusetts commented that the North Atlantic planning area is too environmentally sensitive and contains too little promising acreage to justify leasing. The Florida Public Interest Research Group stated that they do not object to the proposed location of sales. Maryland, New Hampshire, New Jersey, South Carolina, and Virginia stated their general agreement with the proposed locations.

California: The City of Eureka endorsed proposed leasing in the Northern California planning area.

On the other hand, several local governments (listed above), the Marin Conservation League and the California Public Interest Research Group noted the location of sales off California in resolutions stating general opposition to the Draft Proposed Program. Both the City and County of Santa Barbara opposed the draft proposed leasing schedule. The Association of Monterey Bay Area Governments and the Monterey Bay Unified Air Pollution Control District expressed opposition to leasing in the Central California planning area. The League for Coastal Protection commented that no leasing should take place in the Central and Northern California planning areas until studies are completed. The Environmental Coalition stated opposition to leasing off the entire west coast. Several citizens of California submitted comments, the great majority of which opposed the location of lease sales off California.

Gulf of Mexico: Alabama commented that the Draft Proposed Program made a reasonable proposal for leasing in the Central and Western Gulf of Mexico and that leasing in the Eastern Gulf of Mexico should be accelerated if there were a discovery there. Texas and Louisiana did not dispute the appropriateness of leasing in the Gulf of Mexico, but rather commented on the desirability of a balanced national program.

Washington-Oregon: Oregon gave qualified approval for including the Washington-Oregon planning area in the leasing schedule but requested that the planning area have a seaward boundary of 125° W longitude. Washington requested that lease offering be limited to promising geologic structures. Greenpeace commented that leasing should not be conducted in the Washington-Oregon planning area.

Timing Comments (where different from Location Comments)

General: The EPA recommended that the range of alternative leasing schedules proposed be widened to provide longer intervals between sales in certain areas where triennial sales are now proposed. Louisiana stated that holding annual sales in the Central and Western Gulf of Mexico OCS planning areas and triennial sales in other areas will result in increasing the rate of depletion of the

resources in the former areas and prolonging the life of those in the latter areas. Alaska, Connecticut, Delaware, Florida, Georgia, Maryland, New Hampshire, North Carolina, Rhode Island, South Carolina, Virginia, and Washington agreed with the proposed number of sales and interval between them.

ARCO and Texaco concurred with the proposed leasing schedule. The U.S. Chamber of Commerce and the Alaska Oil and Gas Association stated their general opposition to deceleration of the pace of leasing. Sohio and Tenneco stated their agreement with annual leasing in the Central and Western Gulf of Mexico planning areas and their opposition to slowing the pace elsewhere, particularly in the Eastern Gulf of Mexico planning area. They also raised the concern that the triennial leasing pace is not compatible with regulations requiring public release of well information 2 years after its date of submission. Union Texas Petroleum, Chevron, BP Alaska, Shell, NOIA, Exxon, Amoco, Western Oil and Gas Association, and API generally agreed with the annual pace of leasing in the Gulf of Mexico and stated their preference for biennial leasing in most other planning areas. Several of these companies made specific recommendations for scheduling in particular planning areas, and Exxon presented a complete alternative 5-year schedule. Fairfield Industries concurred with the annual pace of leasing in the Central and Western Gulf of Mexico planning areas, but suggested having 6 months' separation between Central and Western Gulf of Mexico sales, commencing in 1986 rather than 1987. Marathon endorsed annual leasing in the Central and Western Gulf of Mexico planning areas and stated support for triennial leasing elsewhere as long as acceleration will be possible under certain conditions.

The Massachusetts Audubon Society stated that the interval between sales always should be long enough to complete gathering and analysis of environmental information, noting that in some cases the process could exceed 3 years.

Alaska: NOAA stated support for triennial leasing in Alaska OCS planning areas and suggested that the 3-year interval between sales be increased in certain situations.

Atlantic: Maine commented that the proposed triennial pace in the Atlantic is appropriate, but requested more explanation of the schedule before actually endorsing the timing of sales in the North Atlantic planning area. Massachusetts stated that only one North Atlantic sale is warranted during the 1986-1991 period. New Jersey recommended deceleration of the sale schedule for both the Mid-Atlantic and North Atlantic planning areas. The County of Volusia (FL) stated that the schedule proposes too many sales during the 5-year program. The Florida Public Interest Research Group stated their agreement with triennial leasing off Florida.

California: The City of Los Angeles supported the triennial pacing proposed for the Southern California Planning Area, but noted that the interval between Sale 80 and proposed Sale 95 is 2½ years. The City of Pismo Beach recommended that the number of sales be reduced and the interval between them expanded. The County of Ventura commented that the triennial leasing schedule is welcome. The City of Santa Monica stated they are encouraged that the proposed schedule slows the pace of lease sales. Get Oil Out, Inc. stated that triennial leasing is a step in the right direction. Greenpeace cited triennial leasing as a general improvement, but stated that it does not change the situation of California as a whole.

Table 13.1

Industry Interest in OCS Planning Areas /1
Summer 1984

Overall Ranking/2		Range of Companies' Rankings/3
1	Central Gulf of Mexico	1 to 5
2	Western Gulf of Mexico	1 to 7
3	Beaufort Sea	1 to 7
4	(tie) Southern California	1 to 11
4	(tie) Central & Northern California	3 to 14
6	Eastern Gulf of Mexico	3 to 12
7	Navarin Basin	2 to 11
8	North Aleutian Basin	3 to 14
9	St. George Basin	3 to 15
10	Chukchi Sea	2 to 13
11	North Atlantic	7 to 22
12	Norton Basin	8 to 18
13	Washington-Oregon	5 to 21
14	Mid-Atlantic	9 to 23
15	Hope Basin	10 to 19
16	Cook Inlet	9 to 20
17	Shumagin	12 to 22
18	South Atlantic	10 to 24
19	Gulf of Alaska	12 to 21
20	St. Matthew-Hall	14 to 23
21	Kodiak	13 to 24
22	Bowers Basin	16 to 24
23	(tie) Aleutian Arc	12 to 24
23	(tie) Aleutian Basin	15 to 23

/1 This table has been included for comparison with the current industry rankings in Table 13.2. Note however, that a one for one comparison is not possible since, among other things, the number and configuration of planning areas have changed, exploration results since Summer 1984 may have affected rankings, and future price expectations of individual companies may have changed. This table is based on responses from 18 companies, not all of which ranked all areas.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

Table 13.2

Industry Interest in OCS Planning Areas
Spring 1985

	Overall Ranking/1	Range of Companies' Rankings/2
1	Central Gulf of Mexico	1 to 2
2	Western Gulf of Mexico	2 to 5
3	Beaufort Sea	1 to 6
4	Southern California	1 to 8
5	Eastern Gulf of Mexico	3 to 10
6	North Aleutian Basin	3 to 9
7	Central California	4 to 11
8	Navarin Basin	4 to 10
9	Northern California	4 to 11
10	Chukchi Sea	4 to 20
11	St. George Basin	8 to 17
12	Norton Basin	9 to 18
13	Hope Basin	9 to 19
14	North Atlantic	12 to 17
15	Mid-Atlantic	11 to 21
16	Cook Inlet	10 to 21
17	South Atlantic	12 to 22
18	Washington-Oregon	11 to 22
19	Straits of Florida	14 to 24
20	Gulf of Alaska	15 to 22
21	Shumagin	14 to 25
22	Kodiak	18 to 25
23	St. Matthew-Hall	16 to 26
24	Aleutian Basin	14 to 25
25	Bowers Basin	21 to 26
26	Aleutian Arc	20 to 26

/1 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/2 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

Table 13.2 includes rankings of the nine responding companies, three of which gave partial rankings. This relatively small number limits the usefulness of Table 13.2 as an indicator of the collective interest of all potential producers. Nonetheless, there is a considerable degree of parallelism between industry rankings in Summer 1984 (Table 13.1) and Spring 1985 (Table 13.2).

Table 13.3

Comparison of Net Social Value and Industry Interest Rankings for the Proposed 5-Year Program

Planning Area	Net Social Value	Industry Interest (Spring 1985)
Central Gulf of Mexico	1	1
Western Gulf of Mexico	2	2
Southern California	3	4
South Atlantic	4	17
Central California	5	7
Northern California	6	9
Eastern Gulf of Mexico	7	5
Navarin Basin	8	8
Mid-Atlantic	9	15
Washington-Oregon	10	18
Beaufort Sea	11	3
St. George Basin	12	11
North Atlantic	13	14
Straits of Florida	14	19
Chukchi Sea	15	10
Gulf of Alaska	16	20
North Aleutian Basin	17	6
Norton Basin	18	12
Kodiak	19	22
Hope Basin	20	13
Shumagin	21	21
Cook Inlet	22	16

On the other hand, the County of San Luis Obispo recommended a minimum of 12 months between sales off California and 3 years between sales in frontier areas. The San Diego Association of Governments and the City of San Diego called for no more than one sale every 5 years. The San Francisco Bay Sierra Club Chapter, League of Women Voters of San Luis Obispo County, Environmental Center of San Luis Obispo County, and Whale Center commented that the proposed scheduling would not slow the pace of leasing off California as a whole, since there would be one sale off California per year. Friends of the Sea Otter commented that leasing would be accelerated under the proposed schedule. The Santa Lucia Sierra Club chapter stated that lease sales should be held every 5 years.

Washington-Oregon: Oregon stated that the time proposed for conducting environmental studies prior to a sale in the Washington-Oregon planning area is inadequate.

Gulf of Mexico: Texas commented that the proposed schedule very nearly approximates the current rate of lease sales being held. Greenpeace also commented that annual leasing in the Central and Western Gulf of Mexico planning areas forces those areas to assume a disproportionate amount of environmental and economic costs of development. The Sierra Club Lone Star Chapter (Galveston, Texas) commented that biennial sales in all of the Gulf of Mexico would be sufficient.

Scheduling Sales in High Net Social Value Areas

As can be seen from Table 12.1, the Central and Western Gulf of Mexico areas are clearly the high net social value areas. Each of them has over three times the potential net social value of the next best areas--over the full range of alternate price assumptions. Industry has also ranked these two areas most highly. It may thus be appropriate to hold annual lease sales in the Central and Western Gulf of Mexico, continuing the same timing in those areas as in the 1982 5-year leasing program.

Drainage and field development considerations also figure strongly in the timing of lease sales in the Central and Western Gulf of Mexico. The MMS estimates that because of the level of activity in the Central and Western Gulf of Mexico, there will be about 100 drainage and development blocks in each of those two areas each year. Failure to lease these blocks once drainage begins reduces Federal revenues and could provide unwarranted profits to adjacent leaseholders. Failure to offer development blocks subsequent to nearby discoveries can lead to production delays or less than optimal field development.

Scheduling Sales in Intermediate Net Social Value Areas

The Intermediate net social value group of planning areas (see Part II.D) contains all other planning areas which have a net social value estimate exceeding $0.5 million ($1987) for at lease one of the oil price assumptions: Southern California; Eastern Gulf of Mexico; Navarin Basin; Central California; Northern California; South Atlantic; Beaufort Sea; Chukchi Sea; Mid-Atlantic; St. George Basin; Washington-Oregon; North Atlantic; Norton Basin; North Aleutian Basin; and Gulf of Alaska. Considerable discretion within section 18 requirements is appropriate in scheduling sales in these areas. It would be reasonable to

schedule sales in the intermediate areas in a variety of ways, including biennially or triennially, based a consideration of net social value, industry interest, and other section 18 factors. Further distinctions with respect to scheduling sales in the intermediate group could be made by means of the frontier exploration sale request for interest process.

In interpreting MMS net social value estimates for the purpose of formulating a 5-year leasing program, it should be noted that section 18(a)(2)(E) specifically requires consideration of the interest of potential producers of oil and gas. Of particular significance are those cases in which industry ranks an area differently from MMS (see Tables 13.1 and 13.2 and Appendices B, D, and F). For example, industry ranked the Beaufort Sea in the top three of all areas, whereas MMS resource estimates show Beaufort Sea (not counting estimated gas resources) in the middle rank of all areas. Another example is the South Atlantic, which MMS ranked high whereas industry ranked it low.

There are a number of factors which can cause industry interest rankings to differ from MMS net social value rankings. The MMS net social value ranking is computed from the risked mean resource estimate. Industry commenters may have different estimates of risk or may weigh conditional (unrisked) estimates more highly. Industry interest rankings may also include considerations not reflected in MMS resource estimates, such as existing infrastructure and ease of operations. Finally, some companies may include in their ranking perceptions of potential legal and regulatory hurdles which are not accounted for in net social value rankings.

The Eastern Gulf of Mexico has more resource potential in the high value category than Navarin Basin and about twice the per barrel cost of delay (see Appendix F, Tables 7 and 9). This would suggest that, in general, leasing in the Eastern Gulf of Mexico should have priority over leasing in the Navarin Basin. However, the substantial gain in resource potential at higher prices in the Navarin Basin area contributes to making it reasonable to schedule lease sales there more frequently than in other areas which do not show such substantial gains (see Appendix F, Table 8).

Several areas show substantial gains in resource potential if starting oil prices are higher: Central California; Northern California; Navarin Basin; Eastern Gulf of Mexico; Beaufort Sea; Mid-Atlantic; and St. George Basin (see Table 2). It may thus be reasonable to schedule sales in each of these areas during the 1987-1991 period and to consider additional sales in areas most likely to gain from price increases, new technology, or new data from exploration.

Especially in the case of areas that have not yet been offered for lease, the MMS resource estimating process is limited by the paucity of available drilling data. More data may well lead to a significant revision of resource estimates.

Four areas have never had a lease sale actually held: Chukchi Sea, Hope Basin, Shumagin, and Kodiak. Three other areas have not had a lease sale for twenty or more years: Northern California, Central California, and Washington-Oregon.

It is worth recalling at this point that the net social value figures are planning area estimates and do not reflect the geographic distribution of prospects within a planning area. It is during the presale process that that question is addressed. During the presale process, the balancing of resource, environmental, and multiple-use considerations is performed. For example, in the presale process for Sale 92, North Aleutian Basin, a relatively small part of the planning area has been rated as highly prospective by industry. The presale process for Sale 92 reduced the size of that sale to about 17 percent of the planning area.

Scheduling Sales in Low Net Social Value Areas

The Low net social value group of planning areas (see Part II.D) includes areas estimated to have negligible leasable resources and thus negligible net economic value. Some of the areas in this group are estimated to have resources which are developable (i.e., profitable to develop once found) but not leasable (i.e., not profitable for a firm to bid on, given risk and exploration costs) (see Table 4).

The balancing of benefits and costs for areas with no "leasable" resources must proceed on a per-barrel basis rather than on total planning area estimates. The comparison can proceed by making the assumption--not made by the net economic value analysis whose results are displayed in Tables 1, 2, and 12.1 in the SID--that if some or all of the "developable" resources in these areas were leased, their expected private value (the after-tax net present value for the bidder--see Appendix F) would have to be equal to or greater than zero. Assuming--on the low side--that private value is equal to zero for each of those planning areas, and assuming a $24/bbl starting oil price, it is possible to compute the estimates of net economic value per barrel for those areas (see Table 12.2, above). In all of these areas, the net economic value projection exceeds the social cost projection.

As indicated in Part II.B and Appendix F, one consideration involves the possible increases in leasable resource potential and net economic value that could result from increases in oil prices, new geologic and geophysical data, or other factors affecting costs and risk. One such factor which could change the attractiveness of low-valued Alaska areas would be the lifting of the legal prohibition on the export of oil to Japan. The reduced costs of transporting certain Alaskan oil to Japan could cause the net social value of Alaska OCS oil and gas to rise.

An evaluation of the available geophysical and geological data on which MMS resource estimates are based appears in Table 12.1 and Appendix E. The limitations of the available data as well as the specific mandate of section 18(a)(2)(E) call for recourse to the judgment of potential oil and gas producers as expressed in comments as an important source of additional information (see Tables 13.1 and 13.2 and Appendices B and D). This is particularly so since potential bidders are under no constraints to submit bids and that the planning of leasing activity, therefore, must give considerable weight to expressions of industry interest in order to avoid wasting the planning resources of all parties.

Providing Incentive for the Collection of More Geological Data

In addition to MMS and industry rankings, another consideration with respect to scheduling a sale in an area in the Low net social value group is that it could create an incentive for firms to collect additional data. That consideration is a salient one for areas where there is a paucity of geological and geophysical data (see Appendix E). If additional data resulted in changes in current interpretations of the hydrocarbon potential of an area, leasing there could be pursued; if not, leasing there could be deferred. Section 102(9) of the OCS Lands Act Amendments of 1978 provides a mandate for the early assessment of the oil and gas resources of the OCS.

Effects of Deferring Leasing in a Planning Area

It should be noted that the deferral of an area from inclusion in the leasing program means that, barring a significant revision of the new program, it will not be offered for lease through 1991. As a result, the incentive to gather new geological and geophysical data on such an area could be reduced, so that the data available for deciding whether to include that area in the formulation of future programs could be no better than at present.

It is important to stress that the deferral of leasing in any planning area in the program for 1987 through 1991 in no way affects any United States claims to jurisdiction and control over submerged lands under the OCS Lands Act or the EEZ Proclamation of 1983. Changes in MMS's resource estimates, economic conditions, and/or industry interest may lead, under future 5-year programs, to the offering of blocks located in any planning area not included in the 5-year program for 1987 through 1991. All maps of the new program will continue to show all OCS planning areas, whether leasing is scheduled there in the new program or not.

The schedule options presented here specify only the year in which a sale would be held. Considerations regarding the timing of sales within the year and the timing and description of presale steps are set forth in Appendix L. It should be noted that the number of sales in an area in the new program is not an independent element. Rather, a "triennial" sale, as such, is scheduled for the third calendar year after the last scheduled sale in the area. Because of administrative considerations, for example, balancing workload at the regional and headquarters offices, the interval between triennial sales may be somewhat more or less than 36 months. A schedule showing the option selected and presale steps by month will be issued as part of the Federal Register Notice which will announce the Proposed Program.

Decision Options for the Proposed Program

OPTION 2-a - The Base Schedule of Standard Sales

The revised base schedule adjusts the comparable option selected for the Draft Proposed Program for the new timeframe January 1987 - December 1991 and extends the frequency selected for the new program to the added half-year. The revised base schedule contains 32 sales over 5 years in 17 planning areas. It schedules annual sales in the two areas in the High net social value group (the Central and Western Gulf of Mexico) and triennial sales in 14 other areas in the Intermediate

net social value group (see Part II.D). It schedules sales in all Intermediate net social value group areas, except for the Gulf of Alaska and the Straits of Florida. It defers leasing in the Gulf of Alaska corresponding to the Secretary's February 1985 decision to place Sale 88, Gulf of Alaska/Cook Inlet, on hold. Scheduling a sale in the Straits of Florida is discussed in option 2-b.

The first OCS sale offshore Washington and Oregon since 1964 would be scheduled, given that area's net social value ranking and industry interest. The sale for this area is scheduled late in the 5-year period in order to allow time for the necessary environmental studies to be performed. The time allotted for studies exceeds that required by section 20 of the OCS Lands Act and regulations at 30 CFR 256.82(c), which provide that a study for an area be commenced at least 6 months prior to holding a lease sale for that area.

A single standard sale is scheduled in Shumagin--Sale 86, which is carried over from the current schedule. Industry responses to the Federal Register Notice of October 15, 1984 (49 FR 40228), support the scheduling of an initial Shumagin sale. Shumagin is the only Low group area included in Option 2-a. It should be noted that the quantity and quality of geological and geophysical data for Shumagin are rated Very Poor by MMS (see Appendix E). A second Shumagin sale would be part of Option 2-f. The base schedule defers leasing in all areas in the Low net social value group other than Shumagin, i.e., Kodiak, Cook Inlet, and Hope Basin.

-The Base Schedule Decision Option

OPTION 2-a - Adopt the base schedule of 32 standard sales proposed in the Draft Proposed Program, revised to begin in January 1987 (see Table 14).

OPTION 2-b - Add a single sale in the Straits of Florida in 1991.

As part of the decision on the Draft Proposed Program, the area south of approximately 28° N. latituce was made the new Straits of Florida planning area. No decision on scheduling a sale in that area could be made until the section 18 analysis and consultation requirements had been met for that area.

The net social value range for the Straits of Florida is $14-33 million ($1987) over the $19-29 per barrel variation of alternative price assumptions. This area is ranked 14th out of 22 planning areas shown on Table 12.1. Comments on leasing in this planning area were negative from most parties. Industry ranked the Straits of Florida as 19th out of 26 planning areas in response to the March 1985 request for comments on the Draft Proposed Program.

This decision option provides for adding a single sale in the Straits of Florida in 1991, so that the necessary environmental studies could be performed if this option is chosen.

OPTION 2-c - Defer leasing in any or all of six planning areas.

This option would defer from leasing up to six whole planning areas scheduled for leasing in the Draft Proposed Program which were requested for deferral by various comments on the Draft Proposed Program: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin. This option provides for an exception to the scheduling formula for the base schedule on the basis of section 18(c) and 18(f)(1) comments cited above.

Table 14

Current Leasing Schedule Overlap With Option 2-a for the Proposed Program
(Base Schedule of Standard Sales)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90		108				
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S	
ALASKA										10
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86				
									Total	32

Sales to the left of the vertical line are in the current 5-year leasing schedule.
Sales to the right of the vertical line are a part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

This table has been prepared based on the latest available scheduling information. Administrative considerations may delay the holding of a number of sales--Sales 111, 90, 97, 107, 109, 86, 101, and possibly others. If such a change occurs, the leasing schedule would be implemented so as to factor in that change, consistent with the scheduling policy selected by the Secretary. This also applies to the following two schedule tables.

Some of the decision considerations applicable to this option discussed with respect to subarea deferrals, above also apply to the deferral of whole planning areas. On one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferrals of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, deferrals may be premature and may limit flexibility if made before the availability of the geological, geophysical, and environmental information usually gathered during the presale process for a sale. In addition, deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a 2-year process). This could have a dampening effect on information-gathering concerning areas which are deferred. Thus, deferrals may, effectively, become permanent.

OPTION 2-d - Adopt biennial sales in any or all of eight areas with higher value and/or higher interest.

This option provides for scheduling biennial sales in up to eight planning areas. This option schedules up to 39 sales in the same 17 planning areas included in Option 2-a. It differs from Option 2-a by amending it to schedule biennial sales in up to eight areas with higher value and/or higher interest: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. These areas are relatively highly ranked by MMS in terms of net social value (see Table 12.1) and/or by industry (see Tables 13.1 and 13.2). Indeed, these eight areas were ranked highest--after the Central and Western Gulf of Mexico--in industry interest as expressed in Summer 1984 and confirmed in Spring 1985. This option adds the North Aleutian Basin and St. George Basin to the six areas proposed for biennial sales in the Draft Proposed Program, paralleling the list of areas proposed for possible acceleration.

The benefits of offering these sales biennially instead of triennially is indicated in the cost of delay table (see Table 6) and in the section on the valuation of schedule alternatives.

The selection of this option would increase the workload of MMS. If this option is selected, its implications regarding necessary staff and appropriations will be addressed in the materials prepared in compliance with section 16(b).

Table 15 displays all sales which could be chosen in Option 2-d. It should be noted that the 26 month planning horizon for Alaska sales (from Call to sale) means that some sales accelerated by Option 2-d may appear to be separated by three years on Table 15 (e.g., Navarin Basin) when actually the timing would be approximately biennial.

OPTION 2-e - Designate Frontier Exploration Sales

The Draft Proposed Program scheduled 5 frontier exploration sales in Alaska areas so as to increase the flexibility of the schedule to respond to changes in economic conditions or new geologic and geophysical data. Those five areas are the Gulf of Alaska, Cook Inlet, Hope Basin, Kodiak, and Shumagin (1990). A frontier exploration sale is one for which industry interest is re-examined before the start of the presale process by means of a Request for Interest published in the Federal Register several months prior to the Call and/or the

Table 15

Current Leasing Schedule Overlap with Option 2-d for the Proposed Program
(Biennial Sales in up to 8 areas)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90		108				
GULF OF MEXICO										13
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94		S		S		S	
PACIFIC										8
Southern CA		80			95		S		S	
Central CA	73					S		S		
Northern CA						91		S		
Washington-Oregon									S	
ALASKA										14
Beaufort Sea		87			97		S		S	
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107		S		S	
St. George Basin	70			89		101			S*	
N. Aleutian Basin				92		S		S		
Shumagin						86				
Gulf of Alaska			88							
									Total	39

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*The 26-month presale process for Alaska OCS sales results in the appearance that some of the areas proposed for biennial leasing have triennial leasing. A monthly schedule would show that the following 8 areas are proposed in this option for leasing as near to biennial as possible: Southern, Central, and Northen California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; St. George Basin; and North Aleutian Basin.

annual review of the program under section 18(e). If interest is insufficient to justify proceeding with the sale, it can be delayed. A Request for Interest can then be reissued on a perennial or less frequent basis until interest is determined to be sufficient to hold a sale or the sale is cancelled.

This approach is designed to add flexibility to the program by providing for the reasonable possibility that changes in geologic data and economic or other conditions could create bidding interest in the future in areas which now appear unattractive. For example, a substantial oil price increase (such as might result from an oil supply disruption), if anticipated to be relatively long-term, could make an area now unattractive to potential bidders into one which could be of interest to them. Other information of interest would included new geophysical data; new drilling data; new interpretations of existing data; and new estimates of costs of production. By requesting information and acting on it prior to the issuance of the Call, the risk of inappropriate expenditures for such sales would be minimized. One possible drawback of frontier exploration sales, however, is that the additional uncertainty as to whether they will be held might lead firms to avoid investing in data collection for them.

These sales would be in frontier areas where the assessment of potential oil and gas resources based on exploration results is very inconclusive (see Appendix E). Ensuring the early assessment of OCS oil and gas resources is one of the purposes of the OCS Lands Act Amendments (section 102(9)). In addition, a price increase which could result from an oil supply disruption could make frontier areas more attractive to industry (see Table 4). Finally, the scheduling of frontier sales has been interpreted by the court to have beneficial effects concerning the equitable sharing requirement of section 18(a)(2)(B) (see Part II.C).

-Comments on Frontier Exploration Sales

NOAA suggested that a supplemental studies program be established for planning areas in which frontier exploration sales are proposed.

Maine expressed agreement with the concept of frontier exploration sales with a request for interest step and urged that the concept be applied to the North Atlantic planning area. New Jersey stated that they have no opposition to frontier exploration sales, but stated that the process for such sales must include consultation with the Governors of affected States. Alaska commented not on the concept of frontier exploration sales but on one of the areas proposed for one, Hope Basin, to the effect that it would be beneficial to coordinate with the State of Alaska, which is planning an offshore sale adjacent to that area shortly before the Federal OCS sale.

The Western Oil and Gas Association stated agreement with the proposal to include frontier exploration sales. Exxon commented that only tentative sales should be planned for low interest areas and that industry interest in each proposed frontier exploration sale should be established during annual review of the 5-year program, rather than adding the request for interest presale step. The American Petroleum Institute expressed support for the inclusion of frontier exploration sales, but commented that the sales should be considered "standard" instead of "tentative".

-Frontier Exploration Sale Decision Options (see Table 16)

OPTION 2-e Designate frontier exploration sales as follows:

OPTION 2-e-i - Confirm any or all of the areas designated in the Draft Proposed Program for frontier exploration sales in the Gulf of Alaska, Cook Inlet, Hope Basin, Kodiak, and Shumagin (1991).

OPTION 2-e-ii - Add frontier exploration sale designation to all sales in any or all of the following areas: North Atlantic; Mid-Atlantic; South Atlantic; and/or Washington-Oregon. This option extends the frontier exploration sale category to include other areas of low estimated resources, net social value, and/or industry interest.

OPTION 2-f - Supplemental Sales

This option would add an annual sale to offer a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding year. This option is the same as the one proposed in the Draft Proposed Program.

-Rejected Bid Blocks

The small annual reoffering of blocks which received bids which were rejected in sales held in the prior calendar year in these areas would diminish any delay cost associated with offering the blocks 2, 3, or more years in the future. It would also provide for the timely offering of blocks based on evolving geological and geophysical information and would assure receipt of a fair return to the public for blocks on which the Government possesses the latest data. In 1984, there were nine such rejected bid blocks.

-Drainage and Development Blocks

This option would reintroduce the concept of drainage sales on a basis compatible with the requirements of section 18. (Twelve drainage sales were held in the Gulf of Mexico between 1959 and 1978.) A precedent for this provision exists in Alaska Statutes 38.05.180(d)(1) and (2), which allows the Commissioner of the Alaska Department of Natural Resources to issue leases in an area not included in a State 5-year leasing program if (1) the land to be leased was previously subject to a valid State or Federal oil and gas lease, or (2) the land is contiguous to land under State, Federal, or private leases and the Commissioner makes a written finding, after hearing, that leasing of the land would result in a substantial probability of early evaluation and development of the land to be leased.

A drainage tract is one which has a nearby well on a lease which is capable of producing oil or gas, and the tract could suffer drainage if and when such a well is placed on production. The reservoir is interpreted to extend under the drainage tract to some extent. A development tract is one which has nearby wells on a lease with indicated hydrocarbons and which is not indicated to have a productive reservoir extending under the tract. There should be some indication that some part of the tract is on the same general structure as the proven productive well or wells.

The expeditious identification and offering of drainage blocks would minimize potential losses in their sale value because as drainage continues, the net present value of the block being drained diminishes. In areas other than the Central and Western Gulf of Mexico (where annual sales provide for the expeditious

Table 16

Current Leasing Schedule Overlap with Options 2-a and 2-e or the Proposed Program
(Base Schedule + up to 10 Frontier Exploration Sales)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96[S+]			S+	
Mid-	76			111			S+			
South	78			90			108[S+]			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S+	
ALASKA										15
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86			S+	
Kodiak									S+	
Cook Inlet									S+	
Gulf of Alaska						S+				
Hope Basin									S+	
									Total	37

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.
S+ = Frontier Exploration Sale.

offering of drainage and development blocks), the time intervals between sales could result in substantial losses in bonuses to the Government on blocks identified as drainage and development blocks. Also, failure to offer drainage and development blocks expeditiously could adversely affect the efficient production of the prospect's resources.

Since the largest structure on the OCS covers only approximately 35 blocks, even if an entire structure were offered the number of drainage and development tracts offered would likely be very small compared to the size of a standard sale.

-Compliance with the National Environmental Policy Act (NEPA)

To comply with NEPA, an environmental assessment (EA) would be written on these drainage, development, and rejected blocks sales. If each of the tracts had been covered in an EIS within the last several years, the preparation of an EA regarding the leasing of these tracts could well be sufficient to comply with the requirements of NEPA. However, it may be necessary to prepare a new EIS or a supplemental EIS if the EA finds that significant additional environmental information has become available, or environmental impacts are identified which were not evaluated in a recent EIS.

-Comments on Supplemental Sales

The EPA recommended timely communication on supplemental sales to allow adequate response to national pollutant discharge elimination system (NPDES) permit requests.

Maine stated that the supplemental sale concept is reasonable. Massachusetts commented that the provisions pertaining to supplemental sales are vague and may be inconsistent with the OCS Lands Act. New Jersey stated that adequate consultation with affected States must be a part of the supplemental sale process. North Carolina questioned the statutory authority for supplemental sales and offered the following three suggestions: 1) no block should be offered unless it has gone through an EIS process within the last five years; 2) consideration should be given to the need for a request for interest step in the prelease process; 3) guidelines and regulations should be developed before actually holding any supplemental sales.

The Senate Rules Committee of the California Legislature commented that California faces the likelihood of supplemental sales, and the overall pace of leasing is not slowed if such sales are included in the schedule. The California Department of Justice commented that addition of supplemental sales contributes to ambiguity regarding the timing of sales off California, thereby limiting effective notice as to when and where leasing and development will occur.

The City of Santa Barbara commented that supplemental sales will contribute to an annual leasing pace. The City of Pismo Beach and the county of San Luis Obispo noted supplemental sales in resolutions stating general opposition to the Draft Proposed Program.

Texaco, NOIA, the Alaska Oil and Gas Association, the Western Oil and Gas Association, and the API endorsed the concept of supplemental sales. Shell commented that the provision for supplemental sales should be retained, but it would be an inadequate response mechanism if major discoveries are made. Exxon commented that supplemental sales would be more useful if broadened in scope. Amoco expressed a need for more information describing the supplemental sale provision.

The League of Women Voters of San Luis Obispo commented that supplemental sales could speed up the leasing schedule. The League of Women Voters of Santa Barbara requested that no leases in the Santa Barbara channel or the Santa Maria Basin be offered in supplemental sales. The Natural Resources Defense Council commented that supplemental sales would disrupt the schedule and limit its value as a planning document.

A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon R. Panetta commented that the proposed supplemental sales provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

OPTION 2-g - The Acceleration Provision

The DOI must plan for an unknown future with limited information. Changes in the world energy market as well as exploration results in frontier areas can dramatically affect the demand for offshore leases. The statutory requirement to develop a schedule which will best meet energy needs must be applied with due recognition that what will be known tomorrow may well be very different from what is known today. Thus, the 5-year program needs to have flexibility to adjust to major unforeseen developments.

One means of providing such flexibility is the following provision to permit the acceleration of leasing from triennial to biennial if the following carefully defined criteria are met. The Draft Proposed Program contained a proposal that the acceleration of sales be considered for any of the following eight areas (the same areas listed in the biennial sale option for the Proposed Program): Southern, Central, and Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and St. George Basin. Under this provision, however, the total number of sales in a planning area or in the program would not be increased.

-Statutory Authority

Two provisions of the statute which appear to be most applicable to the acceleration proposal are sections 18(a) and 18(e). Section 18(a) provides that:

> . . . The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he [the Secretary] determines will best meet national energy needs for the five-year period following its approval or reapproval . . . .

The acceleration provision complies with section 18(a) in that the high degree of uncertainty about future hydrocarbon supplies and prices and about the location of future discoveries make such flexibility necessary in order to meet national energy needs.

Section 18(e) provides that:

> The Secretary shall review the leasing program approved under this section at least once a year. He may revise and reapprove such program, at any time, and such revision and reapproval, except in the case of a revision which is not significant, shall be in the same manner as originally developed.

Thus, the Secretary could, "at any time," review the leasing program and make a revision of it. The purpose of including the acceleration provision as part of an approved leasing program is so that its exercise would be the implementation of part of the approved program rather than a significant revision of it.

The DOI has numerous times exercised the authority to decelerate leasing in an area and that procedure would remain unchanged.

-Criteria for Implementation

In the Federal Register Notice of March 22, 1985, announcing the Draft Proposed Program, it was explained that the acceleration provision

> ... would be used only if warranted by changes in economic conditions (for example, substantially higher oil price expectations such as might result from a serious oil supply disruption) or geologic data (such as could come from major new discoveries). The question of whether to accelerate a sale in an area would be made on a sale-by-sale basis, as part of the required annual review of the program under section 18(e). No new sales would be added to the program in any planning area under this provision.

Further specification of the trigger for the acceleration provision is appropriate for the Proposed Program. The Proposed Program could either: specify a particular trigger or multiple triggers; or request comments on a particular trigger or multiple triggers.

Potential Triggers

GEOLOGIC TRIGGER: A major new discovery in an area makes more salient the cost of delay of leasing. The implementing procedure would be the issuance of a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest. This determination would be based on considerations of avoiding costs related to drainage and delays in exploration and production.

It is possible that in the planning areas subject to this provision a discovery could be made that would be commercial if a regional transportation infrastructure existed, however, the discovery would be of insufficient size to support the construction of such a system. If surrounding unleased wildcat acreage and other unleased areas previously thought to be nonprospective and/or high risk (either geologic or economic) would benefit from this additional information so that they would become of leasing interest, exploration could be accelerated--leading to additional earlier discoveries and production than might otherwise occur.

The provision for supplemental sales (Option 2-f) applies only to the areas nearby the discovery, and is thus not a substitute for this form of acceleration.

ECONOMIC TRIGGERS: The choice of an economic trigger is more complicated and it could be useful to receive public comments on a variety of economic triggers before making a proposal. Potential economic triggers could include events or criteria, and the criteria could be retrospective or prospective.

-Event Triggers

Event triggers could be keyed to the activation of established oil emergency response systems, such as the International Energy Agency's oil sharing agreement and the drawdown of the U.S. Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption. The advantage of these event triggers is that they relate to indisputable facts (whether the event took place) and they are keyed to officially mandated mechanisms for response to an oil supply crisis.

Another event trigger could be keyed to a major disruption in Mideast oil supplies. The definition of a major disruption could be left to the Secretary, or a numerical trigger could be set. The trigger could be set as a U.S. oil import shortfall of 3 million barrels/day--the major disruption level used in the Office of Technology Assessment Report, U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability (September 1984), p. 4. Another way of setting the trigger is at a specified drop in daily crude oil exports from the Mideast over a specified period (Mideast to be defined as by the EIA in the Annual Energy Review 1984 [April 1985], Table 94, p. 219).

-Retrospective Criteria Triggers

Similar to an event trigger is a retrospective criterion, keyed to one of various energy statistics over a specified period. The use of historical levels for such figures could provide some guidance, but changes in economic conditions could provide the basis for their being revised. The following criteria could be used, as applied to some reference period to be established.

(1) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit.

(2) Imports of crude oil and refined petroleum products (excluding those for the SPR) equal or exceed a specified percentage of total domestic consumption of petroleum products.

(3) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) increases by a specified amount or percent.

-Prospective Criteria Triggers

A prospective trigger could be keyed to oil price estimates or projections of oil import dependence. An example of such a trigger follows:

Based on the middle forecast of the EIA in its Annual Energy Outlook publication, through 1991:

-net imports of petroleum (i.e., crude oil and refined petroleum products), excluding imports acquired for the SPR, are projected to equal or exceed a specified percent of total United States domestic consumption of refined petroleum products; and/or

-oil prices (defined as U.S. refiners' acquisition cost) are projected** to
--increase by a specified amount or percent; or
--reach a specified level.

In any case, the Secretary could not accelerate a sale unless he made a finding that acceleration from triennial to biennial leasing is permissible on both environmental and multiple-use grounds.

The Secretary's decision to accelerate a sale would be conveyed to the Governors of affected States and announced in a Federal Register Notice at the initiation of the two-year presale process. Responses from Governors, localities, and other affected parties would be considered along with responses received in connection with the standard presale consultation steps, beginning with the Call. Objections to the acceleration of any sale, or reconsideration on the part of the Secretary for other reasons, could result in a decision by the Secretary to restore the sale to a triennial pacing.

-Areas Where Acceleration Could be Implemented

The eight areas proposed for acceleration in the Draft Proposed Program are listed above. For the decision on the Proposed Program, an option has been added to provide that consideration be given to the potential acceleration of sales in any area scheduled for triennial sales.

-Comments on the Flexibility (Acceleration) Provision

Alabama, Maryland, New Jersey, Virginia, New Hampshire, Connecticut, Maine, and Hawaii endorsed the proposed provision. Alabama cited the Eastern Gulf of Mexico planning area as a prime place for application of the provision. Rhode Island stated that the flexibility provision appears to be a good idea, but that more information is needed concerning it. The Department of Energy endorsed the proposed flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy. Chevron, Marathon, Shell, NOIA, Sohio, Union Texas Petroleum, Texaco, Western Oil and Gas Association (WOGA), and Mobil generally endorsed the proposed flexibility provision. ARCO commented that the potential to accelerate sales should be available in all planning areas.

New Jersey emphasized that adequate consultation with affected States must be a part of any implementation of flexibility. Alaska and South Carolina expressed a need for more information about the flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy. NOAA commented that the development of specific guidelines to implement the flexibility provision is of great interest to them. They also stated that acceleration of leasing in the Navarin Basin, Beaufort Sea, North Aleutian Basin, and St. George Basin planning areas should be viewed with caution. BP Alaska, NOIA, Tenneco, Sohio, Union Texas Petroleum, Exxon, WOGA, and U.S. Chamber of Commerce addressed this topic by stressing the need for overall reliability in the program. Exxon endorsed the concept of accelerating sales, but stated a wish to have sales added to the schedule or have biennial leasing at the outset. The Alaska Oil and Gas Association stated that acceleration of sales would be useful in triennial sale areas, but would not be a satisfactory substitute for scheduling frequent sales in high interest areas.

Florida commented that accelerated leasing in certain areas may conflict with the goals of the new 5-year environmental studies program. Massachusetts cited a need for more information and stated that the flexibility provision may be inconsistent with the OCS Lands Act. Oregon requested that the flexibility provision be deleted from the program. The EPA commented that the acceleration of lease sales could cause planning disruptions and uncertainty, citing NPDES permitting as a process which would be affected. They suggested that diligence requirements be changed instead of adopting the proposed flexibility provision. The California Coastal Commission and the California Department of Justice commented that the proposed flexibility provision appears to violate section 18(e) of the OCS Lands Act. The latter agency also stated that it is unclear how the provision would be implemented. The Senate Rules Committee of the California Legislature expressed strong opposition to the proposed flexibility provision. The California State Lands Commission commented that accelerating sales could strain State review of environmental impact statements.

Several California local governments noted the proposed flexibility provision in resolutions stating general opposition to the Draft Proposed Program (cited above). The City of Santa Barbara and the County of Ventura commented that the proposed flexibility provision will help bring about annual leasing. Ventura recommended that sales be scheduled no more than once every 2 years. The County of Santa Cruz commented that the flexibility provision appears to be a major step back for local governments attempting to ensure that location and timing of lease sales is consistent with protection of coastal resources. The City of San Clemente commented that the proposed flexibility provision appears to be inconsistent with the OCS Lands Act. The County of Santa Barbara stated that if a flexibility provision is included in the leasing program, it must be offset by a deceleration provision also included in the program. The City of Lompoc also suggested adding a deceleration provision. The City of Los Angeles commented that the proposed flexibility provision would result in the practice of beginning a new lease sale immediately after one is completed.

The Marin Conservation League and the California Public Interest Research Group cited the flexibility provision in resolutions expressing general opposition to the Draft Proposed Program. The Environmental Center of San Luis Obispo County and Friends of the Sea Otter commented that the flexibility provision gives the Secretary too much discretion at the cost of State and local governments. Greenpeace, the NRDC, and the Whale Center commented that the flexibility provision appears to be inconsistent with the OCS Lands Act. The League of Women Voters of San Luis Obispo commented that the flexibility provision would disrupt the entire planning process for OCS leasing. The League of Women Voters of Santa Barbara requested that the flexibility provision not be applied to leasing in the Santa Barbara Channel and the Santa Maria Basin. The Lone Star Sierra Club Chapter (Galveston, TX) commented that since economic conditions change much more rapidly than exploration and production activities, acceleration of leasing is not warranted. The Florida Public Interest Research Group commented that acceleration is acceptable, but deceleration should also be considered in the program. The Planning and conservation league and the Pacific Coast Federation of Fishermen's Associations commented that flexibility provisions should be the responsibility of Congress. A letter signed by Mel Levine, Bill Lowry, and Leon E. Panetta commented that the proposed flexibility provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

-Decision Options for the Acceleration Provision

OPTION 2-g Provide for the possible acceleration of OCS sales in areas of higher value and/or higher interest from a triennial to a biennial basis (but not so as to increase the total number of sales in any planning area in the approved program).

OPTION 2-g-i Propose or request comments on any or all of the following triggers for the possible acceleration of OCS oil and gas leasing

(A) Geologic Trigger: a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest

(B) Economic Triggers:

(I) Activation of the International Energy Agency's oil sharing agreement
(II) Drawdown of the Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption
(III) Major disruption in Mideast oil shipments
(IV) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit over a specified period
(V) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of total domestic consumption of petroleum products over a specified period
(VI) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) rises by a specified amount or percent over a specified period
(VII) Net imports of petroleum (excluding those for the SPR) are projected by EIA to equal or exceed a specified percent of U.S. consumption of refined petroleum products
(VIII) Oil prices are projected by EIA to increase by a specified amount or percent or reach a specified level
(IX) Items I through VIII above
(X) Other

OPTION 2-g-ii Select areas for the potential acceleration of OCS sales

(A) Any or all of the eight areas selected in the Draft Proposed Program decision: Southern California; Central California; Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and/or St. George basin.

(B) All areas scheduled for triennial sales

3. Estimate of the Value of the Base Schedule Option

The base sale schedule (Option 2-a) presented in this section represents one of the alternatives for lease sale timing and location for the Secretary's consideration in the development of the 5-year program. The base sale schedule consists of 32 sales in 17 planning areas. As described in the options section (Part III.A.2 above), the sale schedule was derived by considering a combination of factors including: net economic value, social costs (reflecting marine productivity and environmental sensitivity), industry interest rankings, and other section 18 considerations. During the presale process, the Secretary will make a determination as to the specific size of the lease sale. The prelease sale decision on size, together with the decisions the Secretary will make on timing and location (as part of the 5-year program), will significantly influence the pace of OCS leasing and development. Consequently, these decisions will influence the timing of costs incurred and benefits realized from OCS oil and gas development. In general, the faster that leases are made available for exploration in the next 5-year program, the sooner production over the subsequent 20 to 30 years will be achieved. In addition, benefits will be higher if the lower cost resources are found and produced first. The objective of the base sale schedule valuation analysis is to establish the link between, on one hand, the rate and sequence of leasing and, on the other, the timing and the magnitude of the benefits that can be expected.

In order to quantify the impact of certain costs and benefits of the base schedule timing and location decision, an analysis was prepared which indicates the present net social value of the net benefits by accounting for the amount of resources which are projected to be leased in each of the scheduled sales for the currently used presale process of focusing on promising acreage (reflecting the decision option selected in the Draft Proposed Program). It should be noted that there is much inherent uncertainty in assessing the amount of resources expected to be leased in each sale. The methodology is discussed in Appendix R.

The sale size ultimately determined by the presale process will affect the amount of resources which are leased during the 5-year program. The rate of leasing resources which could be expected under the tract selection or areawide sale processes will differ from the projections used for the "focusing on promising acreage" process; but, as explained in section III.B., the exact differences are uncertain for many planning areas, and are therefore not assessed on a sale-specific basis for the valuation of the base schedule schedule alternatives. However, in terms of valuation of the schedule as a whole, past leasing experience indicates that the tract selection approach would result in a lower rate of resources being leased during the 5-year program than would be leased under the "focusing on promising acreage" sale process. As a consequence, tract selection sales would result in lower expectation of net social value.

Also, based on past leasing experience, the areawide sale process should be expected, on the whole, to result in a higher rate of resources being leased than under the "focusing on promising acreage" approach. This is the case because "focusing" is expected to preclude the offering of some promising acreage that otherwise could be leased. (See part III.B. for the discussion of size/presale processes). Therefore, given the base case economic assumptions, and the resulting cost of delay analysis in Appendix F, areawide leasing would increase expectations of net social value--assuming that the sales could

be held. If, however, "focusing on promising acreage" increased the likelihood that a sale would actually be held--by, for example, reducing the chances of a sale being enjoined as a result of litigation, then "focusing on promising acreage" could produce the actually higher value. This is clearly a matter of judgment for the Secretary.

Description of Analysis

The data developed for net social value were used to value the sales in the base schedule alternative. However, unlike the net social value calculation which estimated value for all leasable resources if leased at the beginning of 1987, the schedule valuation analysis required estimation of the amount of resources which would be leased at the time of each lease sale. Economic assumptions used are consistent with the base case assumptions for the net social value analysis--i.e., a base case oil price of $24 per barrel (July 1984 starting price), a 1 percent annual real oil price growth, and an 8 percent discount rate.

The amounts of resources projected to be leased in a sale within each planning area are based on those resources which are economically "developable" i.e., resources which are economic to develop, given that they have been discovered. In many cases, these projections exceed the amount of resources classified as "leasable" for purposes of calculating net economic value in Appendix F. The projections of resources expected to be leased and the estimates of leasable resources were generated for different purposes and therefore have different meaning. Estimates of "leasable" resources provide a basis for computing the measure of a planning area's net economic value for a given set of economic assumptions at the start of the next 5-year program. This measure allows for a ranking of the prospective nature of planning areas at that time.

On the other hand, the value of a particular schedule in which resources are leased over the time period beginning in January 1987 depends upon a broader set of factors than simply "leasable" resources to generate sale-specific resource acquisition. (These additional factors are described in Appendix R.)

Thus, while "leasable" resources influence the sale-specific resource levels, the aggregate amount of resources projected to be leased in a given planning area over a 5-year period is not constrained by the "leasable" resources estimated for the net economic value calculations.

In calculating the economic costs and benefits of the base schedule, it is important to take into account not only the value of the scheduled sales, but also the value of remaining unleased resources. To estimate value of the remaining resources, unleased as of the end of the new 5-year program, an assumption had to be made regarding the pace and rate of leasing in each planning area after 1991. For purposes of this valuation analysis, the pace of leasing established for each planning area in the base schedule was continued until all developable resources were exhausted. The amount of resources expected to be leased each year after 1991 was assumed to be approximately that rate projected for the last sale in each planning area. This is an improvement over the methodology used in the 1982 analysis; however, it should be noted that there is great uncertainty surrounding how or if resources would be leased in each planning area during future 5-year programs.

The resulting net social value estimates from this schedule valuation are highly sensitive to the assumptions employed. The ultimate benefits and costs associated with this 5-year program will also differ from the results of this analysis with any changes in the sale timing (e.g., postponement of sales) or with specific lease sale decisions regarding subarea deferrals and sale size in the Proposed Program. Therefore, the assumptions made for the purposes of the valuation analysis, together with the uncertainties associated with estimating economic value and social costs, should be expected to have a compounding effect on the results. Furthermore, the relative uncertainty in the results is, in part, based on the adequacy of data for each planning area. (See Table 12.1 in this SID and Appendix E.)

Table 17 is a summary of the value of the base case schedule of standard sales (option 2-a) and the value of remaining unleased resources associated with this schedule. Given the stated economic assumptions, the present net social value of resources projected to be leased during the 5-year program totals approximately $32 billion; and the value of the remaining unleased resources as of January 1987 is estimated to be approximately $21 billion.

Using the value of the base schedule as a guide, certain conclusions can be inferred about the value of alternative schedules. Each of the alternatives 2-b through 2-h would increase or decrease the value estimate for the base schedule, depending upon the nature of the option. For example, options which add sales or accelerate sales (such as options b, d, f, g, and h) would be expected, on the whole, to increase the expected net social value of the 5-year program. The increase in present net social value for schedules with earlier sales results from the effects of discounting values generated over time to account for society's time preference in exchanging consumption now for consumption in the future (@ 8 percent discount rate). In almost all cases, this benefit more than offsets the loss due to the foregone growth in value from higher resource prices. Where this is not the case, royalties, taxes and the minimum bid reduce the likelihood that such prospects would be leased and developed prematurely. Options which allow for the cancellation or deferral of subareas and sales (such as options 1-c and 2-c) would be expected to reduce the estimated present net social value the base schedule.

The calculation of net social value for the base schedule is an important indication of the economic impacts of timing and location decision for the OCS 5-year leasing program. However, this is only one of the significant factors that the Secretary will consider in his decisions on the 5-year program. Other section 18 considerations are discussed elsewhere in the SID.

Table 17

Discounted Net Social Value of the Base Schedule and Remaining Unleased Developable Resources /1
($Millions, Except Totals)

Planning Area	Discounted Net Social Value /2	
	Base Schedule	Remaining Unleased Developable Resources /3
North Atlantic	147	147
Mid-Atlantic	359	503
South Atlantic	290	855
Western Gulf of Mexico	8,489	7,513
Central Gulf of Mexico	13,859	7,544
Eastern Gulf of Mexico	499	525
Southern California	3,884	1,811
Central California	739	684
Northern California	1,267	342
Oregon-Washington	247	159
Beaufort Sea	550	19
Chukchi Sea	220	236
Norton Basin	42	12
Navarin Basin	1,058	357
St. George Basin	109	289
N. Aleutian Basin	26	4
Shumagin	10	2
Gulf of Alaska	0	45
Cook Inlet	0	10
Kodiak	0	25
Hope	0	6
Florida Straits	0	33
Totals	$32 billion	$21 billion

/1 The uncertainty associated with estimating resources and net social value, as described throughout the text of the SID and this appendix, is compounded in the formulation of a leasing schedule. Furthermore, the relative uncertainty in the numbers in this table is, in part, based on the adequacy of data for each planning area. (See Table 12-1 in this SID and Appendix E.)

/2 Net social value is discounted to January 1987--the projected start of the 5-Year Program.

/3 The values of remaining unleased resources do not include estimates of resources in currently uneconomic prospects which become economical as hydrocarbon prices increase in the future. See Appendix F, section V.C.

III.B. Size Options for the Proposed Program

Comparison of the Three Presale Approaches

Three basic presale approaches have been used for OCS general lease sales: (1) "tract selection;" (2) the initial "areawide" process; and (3) modifications of the areawide approach--most recently, focusing on promising acreage. These approaches will be described and compared with special attention to their effects on multiple-use and environmental considerations, planning and coordination with States and localities, and exploration.

The current presale process (described in detail in Appendix L) extends over a period of about 2 years.

To compare the tract selection, areawide, and focusing approaches one needs to consider a wide range of issues some of which will be addressed here and others elsewhere in the SID. Comments on this issue which were received in response to the March 1985 request are summarized in Appendix B. Fair market value considerations are discussed in Part II.E and Appendices K and P. Further data and analysis on the tract selection and areawide leasing approaches appear in Appendix P.

Overview

Historically, these different approaches represent distinguishable combinations of policies and procedures under different Secretaries of the Interior. The tract selection approach was used until 1982. The initial areawide leasing approach was used in Sale 76, held in April 1983, through Sale 79, Eastern Gulf of Mexico, held in January 1984. A modified areawide leasing approach was inaugurated in January 1984. A further modification, focusing on promising acreage was inaugurated in March 1985, with the issuance of the Draft Proposed Program.

The March 1985 Federal Register Notice announcing the Draft Proposed Program described focusing on promising acreage in the following terms:

> It is proposed that the size of lease sales be determined by a presale process which results in the offering of promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis.
>
> The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

The tract selection sale procedures used in prior years restricted the location and the amount of acreage offered, in part because of opposition to leasing and in part because of administrative constraints on the number of specific tracts that were processed through the environmental impact analysis and presale tract evaluation steps in preparing for lease sales. Tract value estimates were prepared for all tracts to be offered and were completed prior to the date of the sale. As a result of these constraints, only about half of the tracts nominated by potential bidders were offered in the subsequent sale. The tracts selected from those nominated tended to be those that received nominations from more than one or two firms.

One of the objectives of areawide leasing was to give more freedom to oil and gas exploration firms in the location and the rate of investments in exploration and development of OCS oil and gas prospects. A number of procedural changes were made in order to achieve this objective, allowing the higher leasing rates of 1983 and 1984.

The three approaches differ in two general ways. First, the acreage offered for lease tends to be largest in areawide sales and smallest in tract selection sales with focusing on promising acreage in the middle. The largest areawide sale (over 58 million acres) included about 20 times the acreage of the largest tract selection sale (about 3 million acres). Second, tract selection relies more on governmental as opposed to private industry judgment in the course of the presale process. Both the areawide approach and focusing on promising acreage give more weight to a nomination submitted by a single firm than was the case under tract selection.

Focusing on promising acreage differs from the areawide approach in that the former provides more flexibility for the resolution of conflicts early in the presale process--especially concerning low-resource, low-interest acreage. The magnitude and timing of deferrals ("focusing") from sales since January 1984 are documented in Appendix O.

It is possible to combine tract selection or areawide procedures with a variety of policies concerning the size of a sale. For example, areawide leasing procedures can accommodate sales covering a whole planning area or much smaller sales. Likewise, with the post-sale evaluation procedures in place--procedures designed for larger tract selection sales and then used for areawide sales--tract selection sales could be larger than their historical limit of 2 to 3 million acres. Nonetheless, the term, "tract selection" as used by most parties connotes the historical approach used in OCS leasing prior to 1982: sales offering generally 1 to 2 million acres.

In addition to the presale procedures for determining the amount of acreage to be offered for lease, it is possible to influence the amount of acreage actually leased in a given sale by appropriately setting the minimum bid that can be submitted. The higher the minimum bid, the lower the number of tracts of sufficient value to be worth acquiring at bids at least that high. Thus the minimum bid is in some ways an alternative or a supplement to presale procedures for controlling the actual pace and timing of leasing. The minimum bid also has competition and revenue effects and is therefore discussed in Part III.C. Other possible approaches to limiting the amount of acreage leased are described in the section on decision options regarding sale size, below.

Comments on the Size of Sales and the Presale Process

Focusing on Promising Acreage: Alabama, California, Delaware, Maryland, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virginia generally agreed with focusing on promising acreage as a presale process. The Southern California Association of Governments and the County of Ventura endorsed the concept of promising acreage as a constructive alternative to areawide leasing. BP Alaska and Texaco stated agreement with the process. Get Oil Out, Inc. endorsed efforts to limit the size of areas proposed for lease and the Florida Public Interest Research Group commented that focusing on promising acreage offers significant improvement over the current process. NASA, NOAA, and the U.S. Department of Justice stated agreement with this presale process. NOAA emphasized the importance of early definition of geologic structures and the U.S. Department of Jutice noted that this process will provide flexibility and serve to ameliorate possible leasing concerns.

On the other hand, several California local governments submitted resolutions stating that this presale process would not permit adequate consideration of local use priorities, commercial fishing conflicts, or local agency input to leasing decisions. The City of San Clemente also expressed opposition to the promising acreage presale process. Massachusetts Audubon Society, Greenpeace, and NRDC stated their opposition to focused leasing (Greenpeace and NRDC also failed to perceive a difference between the areawide and focused approaches). The same three organizations also commented that adequate environmental impact statements cannot be written under the areawide or focused process. NRDC posed several questions requesting more specific information concerning the proposed presale process. The Marin Conservation League and the California Public Interest Group cited focusing on promising acreage in resolutions expressing general opposition to the Draft Proposed Program.

Louisiana, Rhode Island, Texas, and the Southern California Association of Governments requested clarification of the focusing on promising acreage process. Washington commented that focusing on promising acreage is an improvement over the areawide process, but does not fulfill the need for a process which provides for identification and deletion of certain areas. Florida stated that areas of deferral and actual industry interest for a sale should be decided before the draft EIS prepared for that sale is released. The City of Los Angeles commented that the concept of promising acreage will not change appreciably the leasing process for the Southern California planning area.

Shell, NOIA, API, Sohio and Exxon cited inequities in the procedures governing submission of positive and negative lease sale nominations, and they requested that the procedures be made similar for both types of nominations. Exxon and Arco expressed concern that the proposed emphasis on consensus could cause unique exploration philosophies held by one or a few companies to be ignored or discounted.

Tract Selection Sales: Alaska stated a preference for returning to the tract selection process or an analogous focused process to facilitate impact analysis. The California Department of Justice, City of San Diego, and San Diego Association of Governments also expressed support for the tract selection prelease process. Massachusetts commented that smaller sale areas should be defined to allow States to concentrate better on those areas likely to be leased.

Areawide Sales: Texas Petroleum, NOIA, Alaska Oil and Gas Association, WOGA, API, and the U.S. Chamber of Commerce stated their preference for areawide leasing.

On the other hand, Oregon reiterated a request for abandoning the areawide leasing process. The California Department of Justice and the City of San Clemente expressed opposition to the areawide process, and letters from citzens which addressed the topic presale process were against areawide leasing.

Other comments: Tenneco stated their support for early resolution of potential conflicts, but identified the "drilling window" concept applied to the Eastern Gulf of Mexico Planning Area as an impediment to exploration and development. All comments are described in further detail in Appendix B.

Presale Procedures for the Different Approaches

The key differences between the three approaches can be seen in the early presale steps. The first step in a tract selection decision process is the Call for Nominations. The Call for Nominations asks industry to nominate tracts or descriptions of areas within the Call area. Companies are requested to rank tracts or areas nominated by priority of interest (high, medium, low). The Call also requests comments from the States, other Federal Agencies, and the public regarding which tracts or areas should or should not be considered for leasing. Comments and nominations are analyzed by the MMS along with environmental profiles and data on the area, including geologic and resource data and information from resource reports requested from other Federal Agencies prior to issuance of the Call for Nominations.

After consultation with affected States, there is a tentative selection of tracts or areas to be analyzed further in the EIS as the proposed Federal action. The tract selection approach usually narrowed down the size of the sale area to tracts or areas rated high or moderate in geologic potential by the MMS and tracts or areas nominated by a number of firms determined on a sale-specific basis up to the maximum administratively-determined size of the sale. A tract or area nominated by a single firm, even if ranked high priority by the firm, was not assured of selection for further study (even before the questions of multiple-use and environmental protection were reached). In the past, the maximum size of tract selection sales was between 2 and 3 million acres.

Under the initial areawide approach, the Call for Nominations was replaced by the Call for Information. The Call for Information can request information and expressions of interest (nominations) on virtually an entire planning area and on MMS's identification of the area of hydrocarbon potential within the planning area, as well as information on particular tracts or areas.

A modification of the areawide approach was the transition from the Call for Information to the Call for Information and Nominations which was made with the publication of the Call for Sale 109, Barrow Arch (50 FR 3870, January 28, 1985).

Focusing on promising acreage contemplates the further modification in which Call areas could be tailored on a case-by-case basis to exclude parts of the planning area. For example, the Call for Sale 110, Central Gulf of Mexico, and the 1987 Western Gulf of Mexico sale excluded the environmentally sensitive Flower Garden Banks from the Call area.

In both the areawide and focusing approaches, potential bidders are asked to outline areas or tracts in the planning area, within or beyond the area of hydrocarbon potential depicted by MMS in the Call, which they believe to have hydrocarbon potential and in which they might be interested in leasing. All interested parties are requested to comment on possible environmental effects and use conflicts. The scope of the information obtained by MMS ranges from broad area information to tract-specific information. In the focusing approach, other information may be solicited in a more precise form. For example, information from potential bidders has been requested on areas which had been deleted in past sales in the same area.

The Area Identification step is a formal decision on the area whose offering is analyzed as the proposed action in the EIS. This step roughly corresponds to the tract selection step. The information received from the Call, along with other information, is used to decide what areas, if any, should be deferred from further consideration at that point.

MMS uses the responses from potential bidders to identify promising areas, taking into account the collective judgment of the oil and gas industry as well as its own. In the case of the initial areawide approach, MMS added to that promising acreage other acreage which was not nominated which filled out a broad area outline. The focusing approach, in part, concentrates more on geological basins as identified by MMS and industry responses to the Call, omitting areas where MMS sees no hydrocarbon potential and resolving problems or conflicts that have been identified. For example, 61.2 million acres were deferred in the Area Identification decision for Sale 111, Mid-Atlantic.

The Size Range of Areas Selected, Identified, Offered, and Leased

-Examples

The following statistics are provided to illustrate the range of the size of the area identified as the proposed Federal action, the area offered, and the area leased under each presale approach.

Under the tract selection approach, the acreage selected in the tract selection step ranged from about 400,000 acres to about 3 million acres. The acreage offered had about the same range. The area leased ranged from about 300,000 acres to about twice that amount.

The largest area identified under the initial areawide process was in Sale 79, Eastern Gulf of Mexico, about 58 million acres, while the smallest was in Sale 76, Mid-Atlantic, which identified 25.4 million acres. The areas offered by those sales were 50,632,000 and 22,671,000 acres, respectively. The area leased in the first sale was 898,000 acres and in the second, 211,000 acres.

Reflecting revisions made under the modified areawide approach, the smallest modified areawide proposal (Sale 92, North Aleutian Basin) identified 5.7 million acres (about 17 percent of the planning area). The largest modified areawide proposal (Sale 94, Eastern Gulf of Mexico) identified 50.8 million acres (which is 7.2 million acres less than Sale 79 identified in the same area). In terms of the size of the planning area, Sale 79 identified the entire planning area, whereas Sale 94 identified about 88 percent of the planning area. It is illustrative of the flexibility of focusing on promising acreage that the decision on the proposed Notice of Sale for Sale 94 reduced its area from the over 50 million acres identified for study to about 37 million acres, based on coordination with affected States and other parties. Neither Sale 92 nor Sale 94 has been held yet.

Focusing on promising acreage may well be characterized by an even wider range. In the Central and Western Gulf of Mexico, DOI has been evaluating the possibility of restricting leasing to within 2,400 meters water depth. In the Final Notice for Sale 98, Central Gulf of Mexico, and Sale 102, Western Gulf of Mexico, blocks in water depths greater than 2,400 meters were deleted from the sales. In Sale 102, however, four blocks were leased which touch the 2,400 line and two were leased which are located 3 miles from the 2,400 meter line. Furthermore, in comments in response to the Call for the 1987 Gulf of Mexico sales, five companies expressed high or moderate interest in acreage deeper than 2,400 meters. For those 1987 sales (Sale 110, Central Gulf of Mexico and the 1987 Western Gulf of Mexico Sale), the 2,400 meter line was not imposed at the area identification stage.

-Limits on Projections

Examples like those given above are illustrative of the different presale processes. Projections of future outcomes, however, cannot be performed with great precision because the "presale process" is an abstraction whose concrete implementation can lead to very different results in different planning areas. The results of the presale process is likely to differ both as between planning areas and as between sales in the same planning area because they depend on the following variable factors: (1) MMS and industry estimates of the amount and distribution of undiscovered oil and gas resources in an area; (2) environmental and multiple-use considerations; and (3) the results of consultations with numerous parties, including coastal State Governors, under section 19 of the OCS Lands Act. All three factors are subject to different perceptions by the various parties who participate in the offshore leasing process. The third factor, depending as it does on a consultation process, does not lend itself to reliable predictions.

For example, the implications for sale size of multiple-use considerations such as the location of Department of Defense (DOD) use areas are subject to change based on consultation. In addition, different local attitudes toward oil and gas leasing and other uses of the ocean can lead to very different outcomes of consultations between the Department of the Interior and other parties such as coastal State Governors under section 19 of the OCS Lands Act. Both the Gulf of Mexico and Pacific regions contain significant deposits of commercially

recoverable hydrocarbons under nearshore waters. The large size of Gulf of Mexico areawide sales and the small size of, for example, Sale 80, Southern California (657 tracts), held under "areawide" procedures, clearly illustrates the effect of factors whose implications for the size of a lease sale are not clearly predictable.

Furthermore, in considering the precision with which "leasing activity" can be planned for under section 18(a) of the OCS Lands Act, it is also important to keep in mind the wide gap between offering tracts and leasing them. In the Mid-Atlantic Sale 76, over 22 million acres were offered, but under 1 percent of that area was leased. In the Eastern Gulf of Mexico Sale 79, over 50 million acres were offered, but less than 2 percent of that area was leased. Even in the OCS sale which leased the largest number of tracts (Sale 72, Central Gulf of Mexico), the 623 tracts leased represented just over 8 percent of the acreage offered. Additional examples appear in Appendix O. Among the numerous factors which influence the number of tracts actually leased are the state of the economy, future oil price expectations, individual company strategies, and exploration results in the planning area and in other planning areas. These variables add to the uncertainty in planning the size of leasing activity.

Planning and Coordination with States and Local Governments

Experience with areawide and focusing as well as tract selection sales held to date indicates that in all areas of the OCS, States are able to identify the parts of the proposed sale areas--down to specific blocks--which are of greatest concern to them for environmental or economic reasons. Nonetheless, numerous State and local governments commented that the Federal Government's--and their own--ability to analyze the effects of and coordinate with other governments concerning the offering of broad areas are strained and exceeded as the size of those areas expands (see Appendix B).

In its report entitled "Early Assessment of Interior's Area-Wide Program for Leasing Offshore Lands," the GAO summarized the results of a survey of oil and gas companies, coastal States and national environmental and fishery groups. The GAO concluded that most regarded Interior's planning documents for presale decisions as accurate and complete. Furthermore, most of those questioned believed that the time for review and comments was still adequate.

Multiple-Use Conflicts and Environmental Considerations

The offering of broad areas under the areawide leasing approach heightened the relevance of multiple-use issues. Multiple-use of the OCS is the subject of numerous comments summarized in Appendix B. Multiple-use and environmental considerations are treated generally in Appendices G and H and will be treated more fully in the EIS.

The presale process presents opportunities to receive information on and conduct consultations concerning multiple-use and environmental considerations. Decisions on the size of the Call area and the Area Identification provide the occasion for the early resolution of conflicts over these issues. The focusing approach emphasizes the use of these early decision points to resolve such conflicts that cannot be mitigated through other means--especially with respect to low-resource, low-interest blocks.

During the presale process, MMS coordinates with numerous parties who use the OCS, for example, the Coast Guard, the Navy, and the Air Force. In response to Navy concerns about conflicts in Warning Area 155, a deferral of about 1.4 million acres was made from Sale 94, Eastern Gulf of Mexico. To mitigate operational conflicts with the Navy further, a stipulation has been developed for Warning Area 174 in the southern part of the planning area to restrict spacing of structures during exploratory drilling to allow unimpeded Navy carrier training exercises.

To mitigate use conflicts with Air Force operations in the Eglin Water Test areas, a "time-sharing" stipulation has been developed which sets forth restrictions creating limited, phased access for exploratory drilling. Several "information to lessees" clauses also alert bidders to special concerns regarding other defense-related operations.

The EIS under both the areawide and focusing approaches reviews deferral options as well as measures (such as stipulations) to mitigate potential adverse effects of development on a site-specific basis.

Appendix O documents presale deferrals from sales in the current 5-year program.

Effects on Exploration of the Different Presale Processes

Section 102(9) of the OCS Lands Act Amendments provides that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time." One objective sought when areawide leasing was adopted in 1982 was to expand the amount and location of acreage leased and thus to allow an increase in the rate of investment in exploration. Thus, it is appropriate to consider the effect of the different presale approaches on future exploration of the OCS.

In the Central and Western Gulf of Mexico, lease issuance proceeded under the tract selection procedures at a rate of about 1 million acres per year during the late 1970s and early 1980s. Almost twice as much acreage was offered--about 1.7 million acres per year--as was leased during that same period. Despite the nomination and tract selection process, only half of the acreage selected as promising 20-some months prior to each sale proved worth bidding upon after further evaluation by firms. Areawide leasing expanded the acreage offered in the Gulf of Mexico by a factor of 35. Acreage leased expanded from 1 million acres per year to about 5 million acres. This shows a very substantial increase in the amount of acreage evaluated, bid upon, and acquired by offshore lessees.

The comparison of postlease exploration activity suggests that areawide leasing has had a favorable effect on investment in exploratory drilling. Although leases resulting from areawide Sales 72 and 74 have been in existence only a short time, drilling activity, based on the number of leases drilled, seems to be proceeding at a higher rate than it did as a result of previous tract selection sales (see Appendix P). The GAO report on areawide leasing also examined the effects on exploration. It concluded that "exploration is progressing at a faster rate under the area-wide program." This report includes data showing that more tracts had been drilled from Gulf of Mexico

Table 18

Producing or Producible Tracts Containing Surface Area Leased More Than Once

Area	Sale	Number of Producing or Producible Tracts Previously Leased
Gulf of Mexico (GOM)	84	None to date
	81	None to date
	74	4
	72	14
	69 Part II	None to date
	69 Part I	6
	67	4
	66	5
	A66	15
	62	1
	A62	14
	58A	12
	58	7
	51	14
	Pre-51	57
	GOM Total	153
Pacific	80	None to date
	68	1
	48	1
	Pacific Total	2

areawide Sales 72 and 74 than from any recent tract selection sales. In addition, a majority of oil and gas companies responding to GAO's questionnaire said that areawide leasing would facilitate exploration and that they have greatly increase their exploration in the Gulf of Mexico as a result.

The areawide approach maximizes the industry's ability to utilize the most up-to-date exploration data and interpretations providing greater flexibility to bid on areas that were of little interest 2 to 3 years prior to the sale, when the Call would have been issued. The areawide approach thus allows the incorporation of late-developing exploration data into both government and industry presale planning more than was the case with the tract selection approach.

Under focusing on promising acreage, the early resolution of conflicts regarding acreage deemed to be low-value and low-interest can result in the exclusion of acreage about which potential bidders could change their opinion by the time of the sale. For example, in areawide Sale 79, a small number of blocks received bids in what had been identified as a low-value, low-interest area.

It is also worth noting that in areawide sales, blocks that had been previously leased and relinquished were again leased. Some were never tested, some were explored but the amount of hydrocarbons discovered was not economical to produce at that time, and others were produced but had not been drilled to horizons now considered prospective. With the present economic conditions, these reoffered tracts are again attractive to industry (see Table 18). A tract selection approach would not have ensured the reoffering of these blocks as soon as under the areawide approach.

While areawide leasing substantially increased the acreage leased and the rate of investment in exploration, continuation of areawide leasing in the 1986-1991 period may not result in leasing and exploration at the rates achieved in the 1983-1985 period. As Appendix P describes, the substantial increases in areas leased that resulted from early areawide sales reflected leasing from an unleased inventory of attractive prospects for drilling that had been built up by the combination of price increases and the smaller offerings under the tract selection procedures in the 1976-1982 period. The substantial amount of leasing that will have occurred in the 1983-1987 period, coupled with substantial decreases in oil price expectations, could leave an unleased inventory with far fewer attractive prospects for the 1987-1992 period. Even with these changed conditions, provicing industry with a wider range of choices through a form of areawide leasing could still lead to the testing of more diverse exploration strategies than under a tract selection approach.

Flexibility

The areawide approaches allow more flexibility to increase rapidly the amount of acreage offered if oil prices increase rapidly again. This could be particularly true if the administrative processes for restricted sales were to be accompanied by reduced administrative capacity (budget and manpower), placing constraints on increases in the acreage to be offered.

The tract selection procedures of the 1970s made it difficult to increase the acreage offered when conditions warranted. The leasing experience of the 1970s shows that the longer the restriction in the availability of prospective acreage, the greater is the buildup of demand for investment and the greater

the potential jump in the rate of investment when acreage is finally made available. The rapid increases in seismic evaluation, acreage leased, and exploratory drilling in 1983 and 1984 could have been smoothed out over 5 or 6 years had more acreage been made available starting in 1977 or 1978.

In summary, the investment consequences of differences in the pace of lease offerings will tend to be greater the more rapid and extensive are the changes in oil price expectations and geological knowledge. Restricted offerings tend to perform adequately in a relatively stable world while wider offerings allow more flexibility for investments to adapt to changing conditions.

Effects of Different Rates of Leasing on Bidding and Revenues

As described in Appendix P, the rates of leasing that result from different presale procedures can affect statistics such as the average bid per acre and the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. The MMS tract evaluation and bid rejection procedures tend to focus on tracts with fewer bids in order to provide added assurances for achieving fair market value. The analysis also shows, however, that both the level of competition and the amounts bid are strongly influenced by the economic value of the inventory of tracts offered for sale.

The set of tracts offered depends upon the size of the sale and nature of acreage remaining to be leased after previous sales. Thus, if relatively little acreage has been offered while tracts appreciated in value, the value of tracts offered could generally increase. Similarly, large sales would tend to offer many more modest and low value tracts along with the high value prospects that would tend to be offered in smaller sales. Average bid statistics reflect these differences, with bids declining as areawide and focused sales proceeded, particularly in the Gulf of Mexico where a sizable unleased inventory of attractive prospects had accumulated. Declines in the average bid due to such effects are not indicative of failure to meet the fair market value requirement.

Changes in economic conditions and the physical or geological characteristics of the tracts leased can also occur over a period of leasing. If such changes generally reduce the economic value of the tracts offered in subsequent sales, average bids will decline. The decreases in oil price expectations since 1982 and the trend toward leasing more tracts in deeper water having smaller prospects or in higher cost areas contributed to the decline in average bids evident in the 1982-1984 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to satisfy the fair market value requirement.

The GAO report on areawide leasing includes a statistical analysis of competition and bonus revenues under tract selection and areawide leasing. It concludes that the average number of bids declined from 2.55 per tract in tract selection sales to 1.65 in the areawide sales it reviewed. It also finds that the tract selection sales between November 30, 1979, and April 25, 1983, had an average bonus of $2,624 per acre whereas the areawide sales between April 25, 1983, and September 30, 1984, had an average bonus of $686 per acre. Of the $1,738 per acre difference, the GAO estimated that $541 was caused by the shift to areawide leasing while $1,397 was due to other factors. On this basis the GAO estimated

that the Federal Government received $5.4 billion (discounted to 1984) less for the tracts leased in the first ten areawide sales than it would have received if the same acreage had been leased using tract selection sale procedures.

The GAO report notes that the OCS Lands Act "does not require Interior to maximize government revenues for offshore leases," though revenues are an important consideration. The GAO observes that under tract selection, industry "paid a premium" which it "has been less willing to pay" under areawide leasing. It also acknowledges that "some of the estimated reduction in bonus revenue due to the increased pace of areawide leasing will be offset by earlier receipt of royalties, rents and taxes which continue for many years after a tract is placed in production." The GAO analysis has been reviewed by MMS, as set forth in the letter to the Honorable Jack Brooks, Chairman of the Committee on Government Operations of the House of Representatives, signed by MMS Director Bettenberg on September 30, 1985, which is included in the SID by reference.

Appendix P provides more recent data on leasing and exploration, and reports preliminary efforts to estimate the effects of earlier receipt of non-bonus revenues. It identifies a number of deficiencies in the statistical analysis which seriously undermine confidence in the GAO's estimate of the bonus reductions caused by areawide leasing. While many of these deficiencies are highly technical, the difficulty of isolating the bonus effects of areawide leasing from the effects of other factors can be gauged from the difficulty in measuring some of these other factors. For example, bidders' expectations about future oil and gas prices have been changing substantially during the 1979-1985 period. It is unlikely that such changes in bidders' expectations are accurately measured by forecasts of future prices by MMS or any other individual forecaster.

Similarly, it is unlikely that measures of the resource potential of the tracts leased accurately reflect the variations in individual bidders assessments of the resources, given the mixed results of exploration in recent years. Changes in firms optimism about the prospects for new discoveries would clearly affect their bids (and the level of competition) but are difficult to measure for purposes of a statistical analysis.

Appendix P summarizes preliminary analyses by MMS of the overall revenue effects of earlier leasing and shows the substantial gains to the Treasury that can be realized. The leasing in the Gulf of Mexico is the best example of such effects. In 1983 and 1984, 1,029 tracts were leased in the Gulf of Mexico under the areawide and promising acreage approaches. Had these same tracts been leased under the tract selection approach, which typically leased 200 tracts per year, it would have taken about 12 years to complete their leasing. All of the revenues--bonuses, rents, royalties, and taxes--paid as a result of these leases occur earlier (except, of course, the revenues form the 200 tracts that would have been leased in 1983 under tract selection). In fact, revenues from the last 200 tracts leased in 1985 have been moved up by about 9 years. Appendix P shows that, because of these gains to the Treasury, areawide leasing could have reduced bonuses by as much as $8.5 million per tract without causing an overall loss.

Furthermore, leasing and search for oil and gas is a sequential process in which new prospects are identified each year using the results of exploration from previous years. Tract selection leasing would have limited the rate at which industry searched through the many prospects made attractive by the price

increases of the 1970's. Areawide leasing in the 1983-1985 period has made it possible to advance the exploration of all resources that are currently economical by as much as 9 years. Further advances will be realized for as long as the areawide leasing and exploration rates exceed those that would have resulted form tract selection leasing. These advances in the timing of the development of all currently economical resources yield gains in increased economic benefits. It is difficult to specify with much certainty the economic conditions and resource development over the next four decades, even in the Gulf of Mexico. However, under reasonable assumptions, it appears that advances in development under areawide leasing could yield gains of $8 to $12 billion in the present value of oil and gas realized from resources yet to be leased in the Gulf of Mexico.

As of October 7, 1985, 17 comments have been received on Appendix P (as revised on July 15, 1985) in response to the August 19, 1985, Federal Register Notice. The responses of Maryland and Connecticut both question the validity of using data from a mature producing area, the Gulf of Mexico, to draw conclusions about areawide or tract selection leasing for frontier areas. Maryland again recommended that a 50-mile buffer be established for use of the tract selection process within that buffer and the use of the areawide process outside it. Respondents from three State agencies expressed continued opposition to areawide leasing. The Maine State Planning Office stated that the appendix was more a response to areawide leasing critics rather than a policy analysis. New Jersey still supports focused leasing, and Louisiana favors a steadier paced leasing program rather than an accelerated program. California finds that there is little data specific to the areawide leasing consequences for that State.

Because Virginia offshore resources were not involved, the Virginia Deputy Secretary of Resources stated that he would not comment. The NRDC disagreed with certain DOI assumptions, particularly the 8 percent discount rate used throughout the 5-Year Plan and asserted that the profit sharing approach should be examined as an alternative to the cash bonus approach. The Department of Energy, the only Federal Agency to respond, concluded that areawide leasing has increased the present value contribution of total OCS payments to federal revenues by about $3.5 billion compared to tract selection. Their review of the GAO study uncovered significant errors that caused GAO to reach incorrect conclusions. The five respondents from industry all support the areawide leasing approach and basically concur with the Appendix P analysis.

-Decision Options for the Proposed Program

OPTION 3-a Focusing on Promising Acreage

OPTION 3-a-i Use the presale approach of focusing on promising acreage

The process of focusing on promising acreage is described above. It is a flexible approach whose results can range from "areawide" size sales to "tract selection" size sales, depending on MMS resource estimates, industry nominations, environmental issues, and use conflicts. A presale process of focusing on promising acreage provides an alternative and/or supplement to the deferral of subareas at the 5-year program stage for the purpose of achieving an early resolution of conflicts.

OPTION 3-a-ii Solicit comments in the Federal Register Notice announcing the Proposed Program on possible techniques for implementing that approach.

Focusing on promising acreage is an approach open to the development of new techniques for the resolution of conflicts concerning the size of sales. This suboption provides for the solicitation of comments from State and local governments, the oil and gas industry, Federal agencies, and the general public on any or all of the following:

(A) - The recommendation of the Governor of Maryland that the presale process combine the tract selection approach for blocks within 50 miles of shore and areawide procedures for blocks beyond that limit. The advantage of this approach would be responsiveness to coastal States' requests for greater assurance that detailed consideration will be given to areas of greatest concern to them. The disadvantage of this approach is the arbitrariness of the 50-mile figure. If a less arbitrary limit were set, however, it would probably be at the cost of the clarity of the 50-mile proposal.

(B) - Other combinations of areawide and tract selection approaches could also be considered, such as the offering of large amounts of acreage in areas where there have been discoveries and the the offering of smaller amounts of acreage in frontier areas. It has been asserted that this approach could yield nearly the same leasing as the current approach but, by reverting to tract selection in frontier areas, might reduce environmental concern and opposition to leasing. Tract selection sales in frontier areas could offer as much as 4-to-5 million acres, thus assuring the inclusion of most frontier area tracts of interest to bidders. The primary disadvantage of tract selection is the exclusion of substantial acreage early in the presale planning process, limiting bidding to acreage deemed promising on the basis of information that is more than a year old at the time of the lease sale.

(C) - The recommendation of the Governor of Maine that industry nominate in units of 100 blocks. The 100-block nomination units could provide relatively discrete areas for industry indications of interest which would be larger than the nine square miles of a standard block and less than the whole planning area. This approach would help industry protect their proprietary data on specific tracts during the nominations process. Since it may not be practical to establish a limit on the number of such 100-block units which could be nominated, only areas of no real concern to nominators might be screened out. A difficulty with the 100-block unit approach is the arbitrariness of its size. Another consideration is whether this approach is relevant to all planning areas, since at least some companies have nominated the whole planning area or most of it in past sales, for example, in the mature Central and Western Gulf of Mexico.

(D) - The recommendation of Massachusetts that nomination procedures be revised so as to request more detailed information from industry on areas of interest. While MMS currently has a process for gathering a great deal of information from companies, part of that process involves oral elaboration of written comments by the companies. There are always pros and cons of providing for oral as opposed to written communications with the public. Further issues to be considered here include the possibility of instituting a second nomination round late in the presale process and further discussions with States on the advantages of their concluding agreements with the DOI providing for the inspection of proprietary data under section 26 of the OCS Lands Act.

(E) - The recommendation of the API, NOIA, and a number of oil and gas producers that nomination procedures be revised so as to request more detailed information concerning "negative nominations." The object of such a request would be to elicit additional information useful for the Secretary's sale-specific decisions under the OCS Lands Act. Issues to be considered include whether public commenters have the capability to provide detailed information which may be costly to acquire; and the degree of sufficiency of the store of data already available to MMS through over $400 million worth of environmental studies performed to date.

(F) - Proposals to limit the amount of acreage leased through limiting the award of leases. For example, after deferring blocks, as appropriate, in order to avoid environmental and multiple-use conflicts, offer the remaining blocks, but place a cap on the number of leases to be awarded corresponding to a percentage of the total planning area or a fixed number determined on a planning area basis, with leases to be awarded in the order of the high bids. On one hand, this approach could provide more predictability of the maximum potential amount of leasing activity. On the other hand, setting a limit on the number of leases to be awarded may be arbitrary both as applied to a particular sale and insofar as it may be seen as a precedent for other sales, even though the original reasons for setting it might not be applicable.

(G) - Items A through F above

(H) - Other

OPTION 3-b Tract Selection Sales

OPTION 3-b-i Hold sales based on tract-specific nominations generally offering up to 2 million acres.

OPTION 3-b-ii Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations.

OPTION 3-c Hold areawide Sales

For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described above.

OPTION 3-d Other

III.C. Minimum Bid and Bid Adequacy Review Options for the Proposed Program

Section 18(a)(4) of the OCSLA requires the formulation of an OCS leasing program consistent with the principle that

> leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

As discussed in Appendix K, the development of the existing 5-year leasing program included substantial revisions to the policies and procedures for meeting this requirement. The 1982 5-year program was challenged in court on the the grounds that areawide leasing would reduce competition and reduce lease bonuses and that the revised policies and procedures for deciding whether to accept or reject high bids represented an abandonment of previous tract evaluation procedures. The court, in California v. Watt (II), rejected this challenge, finding that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the proposed tract evaluation and bid rejection procedures in order to meet the fair market value requirement.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. In addition, the Department is continuing to evaluate the consequences of areawide and modified areawide leasing to determine their effects on revenue receipts and cash bonuses bid for tracts. This analysis is summarized in Appendix P.

The current bid adequacy procedures are described in detail in Appendix K. Where appropriate, the procedures continue to rely on competitive market forces to assure the receipt of fair market value. However, tracts which fall into certain identified categories, are subjected to additional independent Government analysis to assure that the high bids received adequately reflect the fair market value.

The MMS conducts evaluations of these procedures independently of this leasing program formulation. However, in developing the new 5-year leasing program, there is an opportunity to review the current procedures, evaluate their performance in conjunction with decisions about the size and timing of lease sales, and consider means for continuing to assure that fair market value will be received.

One such evaluation which is being considered for the Proposed Program is a June 7, 1985, draft paper, Analysis of Minimum Bid Policies, which is described in both Appendix F and Appendix K.

In the minimum bid analysis, the current $150 per acre minimum bid level was assessed to determine its effect on:

1. bidding and Government receipts;
2. the appropriate timing for the leasing and development of prospects in different OCS areas; and
3. promoting exploration in high-risk/high-cost areas.

One of the conclusions from the analysis is that the $150 per acre minimum bid requirement has provided an important supplement to bid adequacy procedures and has contributed to significant increases in aggregate bonus revenues. However, it should be noted that higher minimum bid levels can influence the amount of competitive interest for certain tracts and hence influence the number of bids received on these tracts.

The minimum bid analysis also indicated that the minimum bid level is an important policy tool which can be tailored for specific planning areas to encourage efficient exploration and development of OCS oil and gas resources. From the standpoint of economic efficiency, a tract should be leased if its net economic value as developed today is greater than if developed in all future periods. Conversely, leasing of tracts should be delayed if the net economic value is higher if developed in some future period.

Because oil and gas are exhaustible resources, their real value tends to rise over time. This means that the leasing and subsequent development scenario which is best for the Nation may involve a delay in the sale of certain high cost prospects in a planning area even while investments are proceeding on lower cost prospects. Absent some mechanism to prevent the leasing of certain high cost prospects, tracts with positive private value could be leased and subsequently developed too soon, partly because of diligence requirements. In light of this information, it may be desirable to retain these prospects in the Government's inventory until the time when their sale would produce maximum net benefits to the Nation. A model has been designed which will analyze the appropriate size of the minimum bid under different economic conditions. Though use of the model, the minimum bid level can be employed to filter out tracts which, according to MMS estimates, may be better retained until later in time.

The minimum bid was also identified as an important potential tool for promoting exploration in high-risk/hign cost areas. Due to high risks and information externalities, there is a tendency for the private market to relatively undervalue and hence lease less acreage in frontier areas vis-a-vis proven areas. To account for these effects, it may be appropriate to consider lower minimum bids in high risk areas during earlier sales in the 5-Year Program.

However, this finding is inconsistent with the conclusion described above, that there may be some benefits to the Nation in discouraging bidding in certain high-cost areas. Therefore, the objectives of encouraging exploration in high-risk/high cost areas and the objective of leasing based on economic efficiency may be at odds for certain planning areas; and the determination whether or not the minimum bid should be lower or higher would need to be made on a sale-by-sale basis.

Since the minimum bid level has the property of influencing the amount and types of tracts (e.g., deepwater or shallow water tracts) which could be leased, a 5-Year Program decision on lease sale size could be made with consideration to varying the minimum bid. In this way, those concerns surrounding premature leasing; and to a limited extent, concerns surrounding fair market value, could be alleviated with an appropriately set, sale-specific, minimum bid.

Two decision options have been developed for the Proposed Program which reflect the policy implications of minimum bid level and bid adequacy review procedures for the receipt of fair market value, economic efficiency, and for frontier exploration issues. The options presented for decision are as follows:

4. Minimum Bid Options:

   a. Maintain the $150/acre minimum bid and determine on a sale-by-sale basis what changes, if any, are to be made; and

   b. Other.

5. Bid Adequacy Review Options:

   a. Maintain current bid adequacy review procedures and determine on a sale-by-sale basis what changes, if any, are to be made; and

   b. Other.

The selection of options 4-a and 5-a would maintain the current minimum bid policy and the current bid adequacy procedures adopted in the Secretarial decisions of March 11, 1982, (and the May 4, 1982, subsequent decision), until changes, if any, were made for individual sales.